CANADA'S ENERGY OUTLOOK

1996 2020

Natural Resources Canada
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Energy Forecasting Division
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Preface

Natural Resources Canada has been producing long-term energy outlooks for almost two decades. Over the years, the emphasis has varied amongst topics. The core purposes of the Outlook have, however, remained. They are:

- to provide a focal point for assembling the views of the department on energy matters within a consistent framework;
- to identify pressure points and emerging issues in Canadian energy markets;
- to offer a base against which to assess the need for, and the form of policies to address such issues; and,
- to contribute to an informed public discussion on energy and its related economic and environmental issues.

In assembling departmental views, the Outlook has benefitted considerably from the input of other branches. We acknowledge, in particular, the important contributions to the energy demand analysis by our colleagues — Jean-Pierre Moisan, Michel Francoeur, Mark Pearson, Louise Métivier, Cristobal Miller, Alain Paquet and others - in the Energy Efficiency Branch.

A key element in the development of the Outlook is consultation with experts in the public and private sectors. For this Outlook we have made presentations to, and solicited the views of over twenty organizations including the energy departments of every province, Environment Canada, the National Energy Board, the Alberta Energy and Utilities Board, the Canadian Association of Petroleum Producers, the Canadian Gas Association, the Canadian Electricity Association, the Task Force of the Canadian Industry Program for Energy Conservation (CIPEC) and its participating industrial associations, the Canadian Petroleum Products Institute (CPPI), Ontario Hydro, Hydro Québec, Manitoba Hydro, SaskPower and BC Hydro, The Pembina Institute for Appropriate Development, the Motor Vehicle Manufacturers Association and the Independent Power Producers Society of Alberta. We also had the opportunity to discuss the results with the National Emissions Inventory and Projections Task Group, an organization of experts from the federal and provincial governments established by the National Air Issues Coordinating Mechanism.

The objective of these consultations was not to achieve full agreement on every view expressed in this document - that would not have been possible. Rather it was to ascertain whether the facts were correct, to obtain feedback on the results and to receive suggestions on possible modifications. The consultations, have, we believe, produced a broad consensus that the Outlook provides a reasonable, considered view of Canada's energy future. This said, the interpretations and conclusions expressed in this study are the responsibility of Natural Resources Canada alone.

Canada's Energy Outlook is the product of a team of analysts in the Energy Forecasting Division. The credit for the successful completion of this long and complex undertaking belongs to Réjean Casaubon and Ram Sahi, who supervised the analysis, and to the other members of the team - Michel Bérubé, Joycelyn Exeter, Wallace Geekie, Hertsel Labib, Paul Monfils, Jai Persaud, JoAn Rehak, Louis Thériault, Co Tran and Hy-Hiên Tran - who made invaluable contributions to the analysis and to the many presentations of the results. A special note of appreciation is directed to Al Coombs, who recently retired, for his work on greenhouse gas emissions, and also to Debbie Hoodspith for her contribution to the production of this publication.

As noted earlier, the Outlook has been produced to stimulate public discussion of energy issues. In that context, we would be pleased to receive your comments, questions and requests for further information.

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Executive Summary

This report provides a reference outlook for Canadian energy demand and supply and for greenhouse gas emissions over the next twenty-five years. The Outlook has been developed based on extensive consultations with experts in the private and public sectors and a careful examination of the relationships between energy production and consumption and prices, economic, demographic, technological and policy factors. It should be emphasized, however, that the energy future presented in this document is only one of many possible scenarios for Canada. It is, in effect, a judgement of what might happen under a set of plausible assumptions about the future. Obviously, also, the outlook results are more reliable in the mid-term given the difficulty of envisioning specific changes in technology over a long span of time.

It should also be noted that the Outlook is not a forecast, in the strict sense of that term, because one important set of variables - the energy, environment and related policies of the federal and provincial governments - is held constant throughout the projection period. Unchanged policy is not an assumption. Rather, it is a constraint, deliberately imposed, to assess the implications of continuing current policy. In fact, a major purpose of the Outlook is to provide a base against which to assess the need for, and form of, additional policy measures.

Framework Assumptions

Chapter 2 contains the key assumptions underpinning the Outlook. The framework assumptions include energy prices, developments in the U.S. economy and energy markets, Canadian economic growth prospects and the policy setting.

Energy Prices

- World oil prices are assumed to remain relatively flat at around $US 20 (1995$) per barrel over the forecast period. World oil demand is expected to grow from 75 million barrels per day (mmb/d) to 100 mmb/d by 2015. OPEC will meet the lion's share of this additional demand with its production projected to increase from its current level of 35 mmb/d to 60 mmb/d.

- North American natural gas prices are projected to increase modestly to $US 1.90 per thousand cubic feet (mcf) (1995$) by 2000 and $US 2.05/mcf by 2005. No changes in prices are anticipated post-2005. This low price scenario is supported by technological development in both the upstream and downstream segments of the industry.

- As a result of restructuring and the continuation of surplus capacity for the next 10 to 15 years in the electricity industry, current real electricity prices are not foreseen to change over the forecast period.

- Based on modest declines in production costs and moderate increases in transport costs, coal prices, in real terms, are assumed to remain constant during the forecast period.

U.S. Economy and Energy Markets

- With declining oil production and increasing oil demand, U.S. net oil imports are expected to increase from 7.1 millions of barrels per day (mmb/d) in 1995 to 10.2 mmb/d in 2015. Canada will continue to be an important supplier.

- The latest U.S. Energy Information Administration forecast calls for natural gas net imports to increase from 2.8 trillion cubic feet (Tcf) in 1995 to 4.1 Tcf by 2015, with most of the increase provided by Canadian sources.

Canadian Economy and Demographics

- The Canadian economy is projected to grow at an annual rate of 2.2 percent over the next 25 years. By 2000, the Canadian economy will be 12 percent larger than it was in 1995; by 2020 it will be 70 percent larger.

- Population is expected to be 7 million higher in 2020 relative to 1995. More than 60 percent of this increase is related to immigration.

The Policy Setting

- The Outlook assumes that current federal and provincial energy and related policies prevail over the entire forecast period.

- On the energy and environmental front, the Outlook incorporates estimates of the impact of announced federal, provincial and municipal initiatives focussed on energy efficiency and alternative energy and reductions of greenhouse gases (GHG). These initiatives include all the measures either directly related to, or, reflecting the objectives of the National Action Program on Climate Change (NAPCC), in particular the commitments to the Voluntary Challenge and Registry (VCR).

- Important policy elements incorporated in the projection include the current tax system, the Canada - U.S. Air Quality Agreement, additional regulations on fuel quality and refinery operators, and evolving competition/privatization of electricity markets. However, some incomplete policy initiatives, particularly in the environmental area, are excluded such as further measures to attain GHG stabilization, and the Next Steps Smog Strategy.

End-Use Energy Demand

Chapter 3 provides projections of end-use demand for the four principal energy-using sectors: residential; commercial; industrial; and, transportation. Highlights of the demand projections are summarized below.

- Total end-use demand will be 5 percent higher in 2000 and 27 percent higher in 2020 than in 1995.

- Energy demand in the industrial sector grows the fastest at 1.3 percent per annum. By 2020, demand in this sector is projected to be 38 percent higher than the 1995 level, and its share of total end-use demand increases from 43 percent in 1995 to 47 percent in 2020.

- Energy demand in the transportation sector grows at a slightly lower rate of 1.1 percent per annum, and its share of total end-use demand remains relatively stable. Alternate transportation fuels make little advances in the road transportation market, with propane expected to remain the most widely used alternate fuel.

- The residential sector experiences a decline in energy demand, due largely to the strong impact of energy efficiency programs and regulations. The share of this sector to total end-use demand declines from 19 percent in 1995 to 15 percent in 2020.

- Overall, the shares of the major fuels do not change significantly over the long term. Oil, natural gas, and electricity represent about 40 percent, 26 percent and 20 percent respectively of total end-use demand. Somewhat surprisingly, natural gas does not increase its share. Although industrial demand for natural gas increases, this is offset by declining demand in the residential and commercial sectors. This latter result is due largely to regulatory action - moving to mid and high efficiency furnaces and more efficient thermal shells for buildings.

- Energy intensity in end-use sectors is projected to decline by 1.2 percent per year. This is due primarily to the impact of building and equipment regulation in the residential sector and the structural shift in the industrial sector to the less energy-intensive industries.

Fossil Fuel Supply and Trade

Chapter 4 presents the outlook with respect to oil, natural gas and coal supply and trade. Major assumptions and results of the projections are summarized below.

Oil and Natural Gas

- The oil and natural gas industry will reduce its domestic reinvestment of cashflow from 89 percent historically to 82 percent during the projection period. This reduction reflects industry restructuring and increased international investment. Nonetheless, oil and natural gas investment, over the long term, will increase from the levels of the last decade. Annual investment is projected to be $10-11 billion (1995$) over the projection period, an increase of $1 to $2 billion per year over the experience of the last decade.

- Technological advances and diffusion will lower finding and development costs of new reserve additions and increase recovery factors from existing reservoirs. Oil replacement cost declines from the current level of $10.80/bbl to $8.10 by 2002 and natural gas replacement cost remains at 65 cents per thousand cubic feet.

- Total crude oil production increases from 1970 thousand barrels per day (mb/d) in 1995 to 2350 mb/d in 2010 and remains flat to 2020. Total conventional oil production, mainly from the Western Sedimentary Basin, increases slightly by 2000 and then declines at an annual average rate of about 1 percent per year. This decline is more than offset by oil sands and eastern frontier developments.

- Canada remains a net oil exporter throughout the forecast period. Net exports increase from 225 mb/d in 1990 to 720 mb/d in 2010 before declining to 550 mb/d in 2020. It is noteworthy, however, that both exports and imports increase significantly.

- Natural gas production increases from 5.3 trillion cubic feet (Tcf) in 1995 to reach 6.9 Tcf in 2020. Domestic demand increases from 2.5 Tcf in 1995 to 2.8 Tcf in 2000 and 3.2 Tcf in 2020. This increase includes requirements for electricity generation of 0.5 Tcf by 2020. Natural gas exports will continue to increase from 2.8 Tcf in 1995 to 3.1 Tcf in 2000 and 3.7 Tcf in 2020.

Coal

- Canadian coal production increases from 75 megatonnes (Mt) in 1995 to 88 Mt by 2020, reflecting increases in domestic demand for thermal coal. Coal imports, about 10 Mt in 1995, will increase to 23 Mt by 2020.

Electricity Generation

Chapter 5 examines the developments in the electricity market and projects the generation mix. Some of the key observations are:

- Electricity demand in Canada grows at an average annual rate of 1.0 percent for the next 25 years, considerably lower than the 2.6 percent experienced during the past 15 years.

- A significant amount of excess generating capacity exists in all regions of Canada. As a result, with the exception of some site specific developments, no additional generating capacity is required to meet growing electricity demand until the middle of the next decade in all regions of Canada.

- When new or replacement capacity is required, it will not be in the form of nuclear or large hydro power. The existing nuclear facilities will not be replaced when they reach the end of their service life. With the exception of a portion of the Grande Baleine project late in the period, all new hydro developments will be less than 500 megawatts in size.

- The preferred new generation options will be natural gas (combined cycle and cogeneration) and refurbishments of existing coal-fired facilities.

- Electricity generation from renewable sources (i.e. biomass, waste, wind, solar, geothermal, small hydro) will quadruple in volume over the next twenty-five years. Even with this increase, however, renewable electricity will still only provide three percent of total requirements.

Primary Demand

Chapter 6 summarizes the projections for total energy requirements. Primary energy demand represents the total requirement for all uses of energy in Canada, including energy used by the final consumer (end-use demand), demand for electricity generation and energy requirements of oil and natural gas producers.

- Total primary energy demand is projected to grow by nearly 25 percent over 1995-2020, from 11,000 Petajoules (PJ) to 13,500 PJ, increasing at about one percent per year.

- Demand for oil, which declined sharply in the 1980s, is projected to increase by 22 percent over the forecast period, rising progressively to reach its 1980 historical level of about 4,000 PJ by 2020. The transportation sector is leading the demand for oil.

- The demand for natural gas (and LPGs) is projected to grow steadily over the forecast period, rising by 30 percent to 4600 PJ by 2020, compared to the 1995 level of 3500 PJ. The major sources of growth in natural gas demand are the industrial and electricity generation sectors. Demand in the residential sector is in fact declining moderately.

- Demand for coal is projected to diminish initially due to its displacement by natural gas in electricity generation, and then, increase significantly to compensate, in the long run, for the expected reduction in nuclear-generated electricity. While growth in hydro electricity will be modest, averaging half a percent per year, supplies from renewables are anticipated to increase at an annual rate of 1.7 percent.

Greenhouse Gas Emissions

Chapter 7 provides the outlook for greenhouse gas emissions from both energy and non-energy sources.

- The total greenhouse gas emissions from all the sectors are projected to be 8.2 percent higher in 2000, 19 percent in 2010 and 36 percent higher in 2020, compared to the 1990 level.

- Transportation and industrial sectors contribute to the increase over the entire period. The growth in the fossil fuel sector is relatively high until 2005 before stabilizing. Emissions from electrical generation are projected to rise significantly after 2010, when some of the nuclear generation capacity is retired and replaced by fossil fuels.

- On a regional basis, emissions growth during 1990-2000 is expected to be stronger for Saskatchewan and Alberta than for other provinces. Over the long term, however, the difference in growth rates across provinces become less pronounced. Emissions from Ontario (because of the closure of nuclear stations) and from British Columbia (in part due to population growth) will increase more rapidly than the national average. In Alberta, the actions of the oil and natural gas industry, as noted above, serve to keep the growth in emissions below the national average.

- Energy efficiency and the climate change Voluntary Challenge and Registry (VCR) initiatives are anticipated to play an important role in moderating the rise in emissions in Canada. These measures are estimated to lower emissions by 38Mt by 2000 and 108Mt by 2020.

- Several impact analysis were performed to test the sensitivity of the emissions results to changes in economic growth, energy prices, energy efficiency and fuel substitution. Emission levels are sensitive to the rate of economic growth. For example, a 1 percentage point increase in annual economic growth would increase emissions in 2020 to a level almost 60 percent higher than the 1990 levels, compared to 36 percent under the reference case. On the other hand, a one percent per year improvement in energy intensity would hold emissions growth in 2020 to 13 percent above 1990.

Chapter 1

"There may always be another reality
To make fiction of the truth we think we have arrived at."
Christopher Fry
A Yard of Sun

Introduction

The objective of this paper is to provide a reference outlook for energy demand and supply and for emissions of greenhouse gases over the next twenty-five years. The Outlook has been developed on the basis of extensive consultations with experts in the private and public sectors and a careful examination of the relationships between energy consumption and production and price, economic, demographic and technological factors. It is, we believe, a reasonable, internally consistent, view of Canada's energy future. It is not, however, the only possible outcome. The use of any alternate subset of assumptions concerning the future will yield a different result. Obviously, also, the estimates are more reliable in the mid-term given the difficulty of envisioning specific changes in technology over a long period of time.

It should be stressed that the projection is not, in the strict sense of the term, a forecast. This is because one important set of variables, namely federal and provincial energy, environment and related policies, is held constant over the projection period. Maintenance of current policy is not an assumption. Rather, it is a deliberately imposed constraint employed both to examine the implications of the current policy mix and to provide a reference against which to evaluate the need for, and, if warranted, the impact of new policies.

The remainder of the paper is organized as follows:

- chapter 2 provides the major framework assumptions - energy prices, the United States economy and energy markets, Canadian macroeconomic performance and demographics and the current policy stance, including measurement of the impact of government initiatives - upon which the results are constructed;

- chapter 3 reviews the results for energy demand for the end-use sectors - residential, commercial, industrial and transportation;

- chapter 4 provides the projections for the supply of, and trade in fossil fuels - crude oil, natural gas and coal;

- chapter 5 discusses the results for electricity generation;

- chapter 6 summarizes the projections for primary (i.e. total) energy demand which includes fuel use by the energy producing industries; and finally,

- chapter 7 provides the outlook for greenhouse gas emissions from both energy and non-energy sources. The chapter also includes an examination of the sensitivity of the emissions results to changes in several underlying assumptions.

Four annexes complete the document. The first describes the modelling framework used by Natural Resources Canada to produce the Outlook. The second presents the methodology used to project the impact of the many initiatives, including the Voluntary Challenge and Registry (VCR), related to the National Action Program on Climate Change (NAPCC). The third annex provides detailed results, at the Canada level, for the reference scenario (full reference case results, at the national and provincial levels, are available upon request.). The fourth annex provides different conversion factors used throughout the Outlook.

Chapter 2

Framework Assumptions

The level and composition of Canadian energy demand and supply are determined by many factors which are external to domestic energy markets. Among the most important are fossil fuel prices which are largely established in international or North American markets. A further critical set of factors, because of strong trade and other linkages, is the expected economic and energy market situation in the United States. Energy consumption, in particular, is also significantly affected by demographic trends, macroeconomic performance and the structure of the Canadian economy. Finally, government energy, environmental and related policies influence energy consumption and production decisions. Although in this analysis government policy is held constant, it is important to specify carefully the parameters of current policy.

Collectively these factors - international energy prices, developments in the United States, demography, economics, policy and initiatives - constitute the framework within which future energy demand, energy supply, and related greenhouse gas emissions are projected. The assumptions used to construct this framework are described in the remainder of this chapter. Also included is a brief discussion of the approach to measuring the impact of initiatives developed under the National Action Program on Climate Change (NAPCC).

2.1 Energy Prices

This section outlines the energy price assumptions - for crude oil, natural gas, electricity and coal - which frame the Outlook. The major pricing assumptions are summarized in Chart 2.1.

Chart 2.1

Energy Pricing Assumptions

	1995	2000	2010	2020
	$1995			
Crude Oil ($US/bbl) -WTI at Cushing	18.40	20.00	20.00	20.00
Natural Gas ($US/Mcf) - at Henry Hub	1.65	1.90	2.05	2.05
Electricity (¢ Cdn/KWh) - Residential Sector				
Ontario	10.1	9.1	8.4	8.4
Canada	8.3	8.0	7.7	7.7
Coal ($Cdn/tonne)				
Alberta (Domestic Production)	10	10	10	10
Ontario (Imported Coal)	55	55	55	55

World Oil Prices

The Outlook is predicated on relatively low international crude prices, averaging $US 20 per barrel in real terms over the entire projection period. This assumption reflects the continuation of a trend that has existed, with only short exceptions, since the 1986 oil price collapse. It is not argued that oil prices will always remain at the $US 20 level. Weather, stock changes, and various political events will cause fluctuations. Rather it is assumed that such fluctuations will be of short duration with the market fundamentals leading to a rapid return to the $US 20 per barrel value.

Chart 2.2 provides the reference world oil projections from a number of forecasting organizations. With the exception of the International Energy Agency (IEA) all of the forecasts suggest international crude prices in the $US 17 to $US 21 range. Underlying this range is a set of views concerning the evolution of world oil markets. World oil demand is expected to grow from 75 million barrels per day (mmb/d) to about 100 mmb/d by 2015. The growth, of about 1.5 percent per year, will be concentrated in the rapidly developing economies of China, South and South-East Asia.

Chart 2.2

Crude Oil Price Projections

	2000	2005	2010	2020
	WTI at Cushing, 1995 US$/bbl			
IEA	17.72	25.53	25.53	-
CERI	19.00	18.50	18.50	-
PEL	17.00	20.00	20.00	-
PIRA	15.97	15.66	-	-
US-DOE Reference	18.20	19.70	20.40	20.98 (2015)
GRI	16.68	16.68	16.68	16.68 (2015)
NRCan	20.00	20.00	20.00	20.00

Sources: IEA, International Energy Agency, World Energy Outlook, 1996 Edition.
CERI, Strategies and Sanctions: World Oil Market Projections, 1996 - 2011, Study No. 76.
PEL, Petroleum Economics Ltd presentation to NRCan, Summer 1996.
PIRA Energy Group, Retainer Client Seminar, October 1996.
DOE/EIA, Annual Energy Outlook 1997: With Projections to 2015, December 1996.
GRI projections are taken from the DOE/IEA Annual Energy Outlook 1997, p. 76

Production from non-OPEC sources is expected to increase somewhat, to around 45 million barrels per day early in the next century. Although it declines thereafter, non-OPEC production remains above the 1995 level of 41.6 million barrels per day until, at least, 2015. Increases in non-OPEC supply are expected from Latin America, North America, Russia and other republics of the former Soviet Union.

The above implies a call on OPEC production on the order of 60 mmb/d versus 35 mmb/d currently. With Iraq's full return in the late 1990s and the possible commercial involvement of the oil industry in various OPEC countries, the general view is that OPEC should be able to meet this demand comfortably. This view does assume, however, that OPEC continues to be motivated by its current philosophy to achieve revenue gains through volume increases rather than through raising prices.

North American Natural Gas Prices

North American natural gas prices have declined by almost 50 % in the past ten years. This decline was due to increased competition, improved pipeline accessibility, the commoditization of natural gas and the greater use of storage capacity. In the United States, for instance, when prices increased in 1992 and 1993, after several years of decline, industry responded by bringing additional supplies to the market thus forcing prices downwards in 1994 and 1995. The pattern in Canada was essentially similar.

As shown in Chart 2.3, our current view is for only modest growth in natural gas prices. Real Henry Hub prices are assumed to rise from $US 1.65 per thousand cubic feet (mcf) currently to $US 1.90 by 2000 and to $US 2.05 thereafter. This view is similar to that of most forecasters, many of whom have significantly lowered their expectation of price increases over the long term. The equivalent Canadian plant gate price, reflecting transportation costs and locational differences, will be approximately $Cdn 0.90/mcf lower.

Chart 2.3

Natural Gas Prices at Henry Hub

	2000	2010	2020
	US$1995/Mcf		
ARC	2.17	1.88	-
GRI	-	2.35	2.33
Dobson Resource (Average of 17 Consultants)	2.15	2.35	-
US DOE (*)	1.80	2.00	2.12 (2015)
NRCan	1.90	2.05	2.05

Sources: ARC Financial Corporation, Energy Update, November/December, 1996.
Dobson Resource Management Ltd., Survey of Hydrocarbon Price Forecasts, Utilized by the Canadian Petroleum Consultants and Canadian Banks, January 1997.
DOE/EIA, Annual Energy Outlook 1997: With Projections to 2015, December 1996
GRI projections are taken from DOE/EIA's, Annual Energy Outlook 1997.

Factors in both the upstream and the downstream sectors of the industry support this low price view for natural gas. In the upstream sector these relate to the sheer size of the North American resource base and the demonstrated ability of industry to respond to supply shortfalls. The U.S. DOE estimates that the technical resource potential is about 2500 trillion cubic feet (Tcf) in North America with a significant portion of this being commercially recoverable[1]. The U.S. accounts for 60% , Canada for 30% and Mexico for 10% of this potential. The U.S. Gulf of Mexico, in particular, is expected to play a major supply role in limiting price increases. The Gulf contains about 35% of U.S. proved reserves and an estimated technically recoverable resource potential of about 415 Tcf.

1 US DOE/EIA, Natural Gas 1995: Issue and Trends, November, 1995.

Improvements in production technique (such as horizontal drilling), and information technology are expected to drive down replacement and overhead costs, improve deliverability and production and consequently, limit price increases.

Major competitive forces are also expected to emerge in the downstream sector of the North American gas industry[2]. The combined effect of deregulation of the natural gas and electricity markets (discussed later) is expected to create increased competition and cause greater "commoditization" of both sources of energy. The consequence will be downward pressures on prices of both commodities. Technological advances and improvements in information technology are also expected to affect the transmission, distribution, marketing and overhead costs.

Electricity Prices

Major changes are taking place in the electricity industry and many North American electricity markets should be significantly deregulated within 5 to 10 years[3]. The exact form of deregulation is not yet clear. It may combine elements of the breakup of utilities into competing units, privatization and regulatory reform. There is, however, consensus on one point - the traditional rate base approach to electricity pricing will disappear. The process of deregulation has already begun in Alberta, and other provinces are studying scenarios for a comprehensive restructuring of their provincial markets.

The electricity market can be categorized into three distinct functions: generation; transmission; and, distribution. The generation of electricity will be the easiest to deregulate. Competition among generators should result in lower costs and therefore, in lower prices to all consumers. As a natural monopoly, the transmission of electricity would most probably remain regulated, securing full access to markets to all competitors, large or small. The issue for distribution is the separation between client service and the "wires" portions of the business.

The above argument suggests the lowering of retail electricity prices. Further, the electricity market is currently facing a surplus capacity for the next 5 to 10 years in most provinces. In the short term, as the generation of electricity becomes more and more competitive, the basic requirement for services will be shared among the producers. This should reduce the need for reserves, which again should reduce costs. On the other hand, as provincial utilities dispose of their assets, there will be some stranded costs which cannot be recouped at fair

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2 Dar, K.Vinod., "Convergence of Natural Gas and Electricity Industries Means Change, Opportunity for Producers in the US," Oil and Gas Journal, March 13, 1995, pp. 58-94.

3 Snelson International Energy, Competition in Electricity Supply: Implication for the NRCan Energy Outlook Prepared for Natural Resources Canada, June 1996

market value. The Outlook assumes that stranded costs will be recovered through transitional arrangements to share them between electricity users and utilities. Such an assumption will delay the anticipated price reduction for most end-use customers. The likely exception will be major industrial users who have alternative sources of supply, including self generation. Utilities or their successors will have to ensure that wholesale prices are at levels low enough to maintain industrial customers.

As shown in Chart 2.4, the Outlook assumes that most electricity prices will remain constant in real terms throughout the projection period. The one exception is in Ontario, where Ontario Hydro has committed to maintain current rates in nominal terms until 2005 and reduce industrial prices, in response to competitive pressures. The consequence of this will be that industrial prices in Ontario, which are currently about twice those charged by the neighbouring provinces will, by 2010, be only marginally higher.

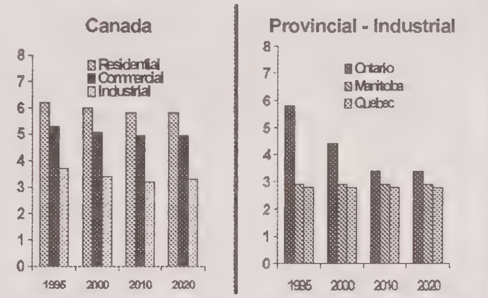


Chart 2.4

Electricity Prices - Cents/KWh ($1995)

Chapter 5 discusses the effect of deregulation on the electricity generation mix.

Coal Prices

Coal, at least as used for thermal generation in Canada, is less subject to commoditization than are oil, natural gas and electricity. Consequently the price of coal in North America is largely determined by production and transport costs.

The production cost of coal is expected to be constant, in real terms, throughout the forecast period. Three major factors constitute the production cost of coal: labour; energy; and, supply and materials. Historically, labour accounts for 40%-50% of total coal production costs, a percentage that is expected to hold throughout the next decades.

Higher wage rates will be more than counterbalanced by higher productivity, and input prices of supplies and materials are expected to increase by the same rate as inflation. Considering these three production factors, the real unit production cost of coal, and therefore prices, will decline by 0.3% per year over the forecast period.

In addition to production costs, the price of coal to utilities and other coal consumers depends on transportation costs which are expected to increase slightly more than the inflation rate. The large differential between Alberta domestic and Ontario imported coal reflects transportation costs.

Overall therefore, the delivered price of coal to utilities is assumed to remain constant in real terms during the forecast period. It must be admitted, however, that this assumption may understate the downward pressure on prices from increasing international competition.

2.2 U.S. Economy and Energy Markets

Canada's energy supply and demand are heavily influenced by U.S. economic and energy market developments. This section summarizes the views presented in the recently published *Annual Energy Outlook 1997* prepared by the Energy Information Administration (EIA) of the U.S. Department of Energy. The EIA's reference case scenario is broadly in accord with NRCan's views and situates our Canadian projection within the North American context.

As shown in Chart 2.5, the U.S. economy is expected to grow by 1.9 percent per year between 1995 and 2015. The annual rate of growth in Gross Domestic Product (GDP) averages 2.3 percent in the first 5-year of the forecast period (1995-2000) and then slows down progressively reflecting a deceleration of the labour force growth after 2005. The GDP growth of 1.9 percent over the period is due to a significant investment growth in the range of 2.3 percent per year.

Chart 2.5

United States: Key Macroeconmic Variables

	1995/00	2000/10	2010/15	1995/ 2015
	Average Annual Growth Rates (%)			
Real GDP	2.3	2.0	1.5	1.9
- Real Investment	3.7	2.1	1.4	2.3
Manufacturing Gross Output	2.4	2.3	1.5	2.1
Population	0.9	0.8	0.8	0.8
Labour Force	1.2	1.1	0.5	1.0

Sources: Energy Information Administration, Annual Energy Outlook 1997, December 1996.

Growth in the manufacturing industries is expected to average 2.1 percent per year until 2015. Energy-intensive industries are expected to grow more slowly than non-energy intensive industries (1.3 percent and 2.6 percent annual growth, respectively). The industrial machinery, electronic equipment, and transportation equipment industries lead the expected growth in manufacturing. The electronic equipment industry is expected to grow twice as fast as manufacturing industries altogether.

The EIA projects U.S. domestic crude oil production to decline from 6.6 million barrels per day (mmb/d) in 1995 to 5.2 mmb/d in 2015. The projected decline in U.S. production is consistent with long-term historical trends. Demand for petroleum is projected to increase from 13.7 mmb/d in 1995 to 15.4 mmb/d in 2015, an average rate of 1.1 percent per year. The transportation sector, which accounts for approximately 70 percent of total demand for petroleum, is projected to increase by 1.4 percent per year through 2015. The decline in domestic production combined with the increase in consumption lead to a growing reliance on petroleum imports through 2015. U.S. net imports of crude oil are expected to increase from 7.1 mmb/d in 1995 to 10.2 mmb/d in 2015. Accordingly, the share of net imports in petroleum consumption is projected to rise from 44 percent in 1995 to 61 percent in 2015. Significant imports from Canada are expected to continue.

The production of natural gas is projected to increase from 18.5 trillion cubic feet (Tcf) in 1995 to 26.1 Tcf in 2015. This represents an average rate of increase of 1.7 percent per year over the forecasting horizon. U.S. demand for natural gas increases from 21.6 Tcf in 1995 to 30.2 Tcf in 2015, which also translates into an average annual rate of growth of 1.7 percent. U.S. net imports of natural gas, primarily from Canada, are projected to increase by 1.3 Tcf over the period 1995-2015, from a level of 2.8 Tcf in 1995 to 4.1 Tcf in 2015 (the latter amount is slightly higher than the projection in this study - see Chapter 4).

Coal production is expected to increase from 937 million metric tons (Mt) in 1995 to 1150 Mt in 2015, which represents an average rate of increase of 1.0 percent per year over the forecast period. Domestic demand for coal is projected to increase by 0.9 percent per year, from 870 Mt in 1995 to 1050 Mt in 2015. Therefore the U.S. is expected to increase its net export position throughout the forecast period.

The U.S. electricity market is rapidly evolving towards a more competitive structure. In the view of the EIA this will result in prices falling almost 15 percent in real terms by the year 2000.

Electricity demand is projected to grow by 1.5 percent a year through 2015. The production of electricity by electric generators is also expected to increase by 1.5 percent per year through 2015, from 3083 Terawatt hours (TW.h) in 1995 to 4139 TW.h in 2015. Coal fired generation will remain the main source of supply, representing more than 50 percent of U.S. capacity through 2015. Natural gas will, however, nearly triple its share of electricity generation, from 10 percent to 29 percent over the forecast period, because of the low cost of natural gas and the lower capital requirements for gas-fired capacity relative to coal-fired capacity. Cogeneration will increase, on average, by 1.0 percent per year, with an increasing share of this production being retained "for own use" rather than being sold to utilities.

2.3 Macroeconomic and Demographic Assumptions

Chart 2.6

Macroeconomic Assumptions

	1995 - 2000	2000-2010	2010-2020
	Average Annual Growth Rates (%)		
US GDP	2.2	2.5	2.3
Canada GDP	2.2	2.2	2.1
- Industry	3.1	2.0	1.9
- Services	1.7	2.3	2.3

	1995	2000	2010	2020
	In Millions			
Population	29.6	31.0	33.8	36.8
Households	10.6	11.2	12.7	14.6
Light vehicles	15.6	16.2	18.4	21.7
Disp. Income/HH($1995)	50,300	49,500	52,200	56,400

Macroeconomic and demographic trends are powerful determinants of energy consumption[4]. As shown in Chart 2.6, Canada's Gross Domestic Product (GDP) is expected to grow, on average, by 2.2 percent per year, a rate slightly below the U.S. economy[5]. Until the end of the century, growth in the industrial sector is assumed to be strong relative to that in services. This differential reflects both an export-led recovery and the fiscal restraint imposed upon the public administration, education and health segments of the service sector (which collectively account for 50 percent of services). Thereafter, industrial growth slows to about 2 percent per year while the service sector expands slightly more rapidly (albeit from a much reduced base). Growth rates for specific industries are examined in Chapter 3.

It is important not to underestimate the cumulative effect of these small growth rates. By 2000, for example, the Canadian economy will be 12 percent larger than it was in 1995; by 2020, it will be 70 percent larger.

Canada's population grows from 29.6 million in 1995 to 36.8 million in 2020, an increase of approximately 0.9 percent per year. More than 60 percent of this increase is related to immigration. The number of households, an important determinant of energy consumption, grows more rapidly (1.2 percent) reflecting complex demographic changes related to the aging of the population. The light vehicle stock (passenger cars, vans, light trucks) increases slightly to 16.2 million by 2000 but grows to almost 21.7 million vehicles by 2020. Also noteworthy are the initial downward trend in real disposable income per household and its subsequent sluggish recovery. These trends have important implications for the capacity of households to purchase new, more energy efficient durable goods and housing.

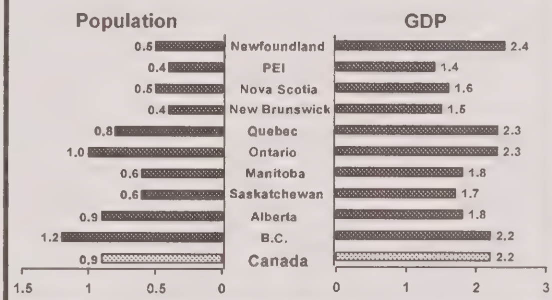
4 The macroeconomic and demographic assumptions are from the Informetrica Winter 1996 forecast. Some elements of the forecast, in particular relating to the growth prospects of specific industries, have been modified following discussions with industry associations.

5 This view of U.S. economic growth from Informetrica is somewhat higher than the one used by EIA particularly for the post 2000 period.

As shown in Chart 2.7, economic prospects and population growth will vary somewhat across regions. Some of the more important regional trends are noted below:

Chart 2.7

Provincial Economic/Demographic Prospects 1995-2020 Average Annual Growth Rates (%)



Atlantic Provinces:

Newfoundland is projected to outperform the other Atlantic provinces because of its offshore oil industry and the development of the Voisey Bay nickel smelter which will stimulate a surge of construction activity in the late 1990s and into the next century.

Nova Scotia will also experience somewhat higher growth than the other Maritime provinces because of the Sable Island Project. In all Atlantic provinces, however, the consumer goods and service sectors will experience only modest expansion because of slow population growth. Consequently, GDP growth for PEI, New Brunswick and Nova Scotia is projected to be below the national average.

Central Provinces:

Economic growth for both Quebec and Ontario is expected to average 2.3 % per year over the forecast horizon. Export-oriented industries, primarily those producing durable, investment and resource-based goods, are the growth leaders for Quebec. However, consumer-related industries are expected to show only moderate improvement because of relatively slow population growth and weak real disposable income growth. For Ontario, electronics, auto and auto parts, and business related services are expected to be the growth leaders. Their performance should more than offset the moderate growth in the resource-based industries and the decline in government and social services. Ontario's prospects will also be enhanced by a relatively rapid population growth.

Western Provinces:

British Columbia is expected to show the strongest population growth of any province with Alberta following at the national average. Manitoba and Saskatchewan are expected to experience GDP performance below the national average. This performance is related to a relatively slow growth for the consumer and service sectors as a result of a low rate of population increase. The Alberta growth assumptions only partially reflect the recently announced oil sands developments.

GDP growth for British Columbia is forecasted to be in line with the national average. Growth areas are expected to be the consumer and service sectors because of the strong demographic outlook. On the other hand, industrial growth prospects are projected to be slightly below the national average.

2.4 The Policy Setting

As noted in the introduction, the Outlook is predicated on the maintenance of current federal and provincial energy and related policy over the projection period. Some aspects of current policy are relatively straightforward to identify. Thus, for example, it is assumed that, consistent with the federal-provincial accords reached in the mid-1980s, Canadian oil and natural gas prices and markets will remain deregulated. Similarly, the elements of the tax system that affect energy - royalties, corporate income tax, excise taxes on motive fuels, the GST and provincial sales taxes - are assumed to remain in place and in their current form.

There are, however, several recent, but, at time of writing, evolving policy initiatives, particularly in the environmental area, for which a decision is required concerning their incorporation. These include the Next Steps Smog Strategy, the Canada/U.S. Air Quality Agreement, the "Energy Chapter" of the Internal Trade Agreement and, most obviously, Canada's commitment to limit greenhouse gas emissions. The process to develop the policy, legislation, regulations and programs for such initiatives is typically protracted, involving lengthy consultations with provincial governments and stakeholders. In some cases, such as the greenhouse gas (GHG) stabilization commitment, the appropriate mix of policy initiatives has yet to be developed.

Chart 2.8

Current Policy - Some Important Elements

- **Included**
  - Continued market orientation (NAFTA)
  - Attainment of federal and provincial deficit targets
  - Current fiscal (tax, royalty) regimes
  - Evolving competition/privatization of electricity markets
  - Federal, provincial and municipal energy efficiency and alternative energy initiatives (including VCR)
  - Canada - US Air Quality Agreement
  - Additional regulations on fuel quality and refinery operators
  - No Megaproject support
- **Not Included**
  - Further measures to attain GHG stabilization commitmet
  - Tightened CAFE standards in US or Canada
  - Next Steps Smog Strategy
  - "Energy Chapter" of the Internal Trade Agreement

The decision of whether to include such policies in the reference projection is a question of judgement. The "rule of thumb" in reaching this decision is to include a particular policy only if the process of giving it legislative or regulatory expression is sufficiently advanced such that an informed public observer could discern the direction and implications of the policy. Chart 2.8 summarizes the results of this decision process for major policy elements.

2.5 Measuring the Impact of the National Action Program on Climate Change (NAPCC) Initiatives

The Outlook incorporates estimates of the impact of announced and likely to be announced federal, provincial and municipal initiatives focussed on energy efficiency and alternative energy and reductions of GHG emissions. These initiatives include all measures either directly related to, or, reflecting the objectives of NAPCC, in particular the commitments to the Voluntary Challenge and Registry (VCR).

The methodology to develop the impact of initiatives, described in Annex B, is complex. In brief, however, the process involves three steps: an understanding of the characteristics of each initiative; a translation of this information into a judgement about market effects; and a calculation of the ultimate impact of each initiative on energy use or emissions levels.

Chart 2.9

NAPCC: Identified Quantifiable Initiatives

		Initiatives				
Major Sectors		Information & Suasion	R&D	Reg's	Fin. Incentive	VCR
End-Use	Residential	46	16	19	6	
	Commercial	87	18	11	2	
	Industry	24	17	6	4	127 (1)
	Transport	11	4	0	0	
Fossil Fuel		-	-	-	-	86 (2)
Electricity		-	-	-	-	11 (3)
Non-Energy		-	1	-	-	1 (4)
Total		168	56	36	12	235

(1) MACIEE commitment of 1% energy efficiency was reflected
(2) CAPP, CEPA and Oil Sands Operation proposed GHG emissions were used
(3) Canadian Electrical Association submission was used
(4) Dupont Chemical's commitment to reduce N_2O emissions from adipic acid production process

NRCan has reviewed several thousand initiatives and identified 272 that can reasonably be expected to achieve definable energy efficiency and/or emissions reduction results[6]. In addition, 235 VCR submissions with quantifiable action plans were examined. These initiatives are categorized by type and sector in Chart 2.9. It is evident that the bulk of the initiatives identified are voluntary in nature. It should be noted, however, that the small number of regulatory measures and VCR commitments account for a large percentage of the total impact of NAPCC initiatives.

The impacts of initiatives, or groups of related initiatives, were developed by identifying the major drivers such as, for regulations, the increased energy efficiency of purchased equipment and the consequences of this increased efficiency as the stock of equipment turns over.

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6 The principal sources of information on the initiatives are: NRCan's Directory of Efficiency and Alternative Energy Programs, The National Energy Board's Survey of Electric Utility Initiatives, the Federation of Canadian Municipalities' database and the Voluntary Challenge and Registry, maintained by NRCan.

Several points should be noted in the assessment of the emissions impact of initiatives:

- conceptually, the estimates are incremental in the sense that the results would not be expected to occur in the absence of the initiative;

- in general the results reflect the incremental impact from 1995. Initiatives in place prior to 1996 are assumed to be already embodied in the historical data . Only additional activity associated with a particular initiative (e.g. a further ratcheting up of energy efficiency standards or additional funding for an ongoing program) is included in the impacts;

- given the complementarity of many initiatives, the results typically reflect the impacts of related measures rather than the individual effect;

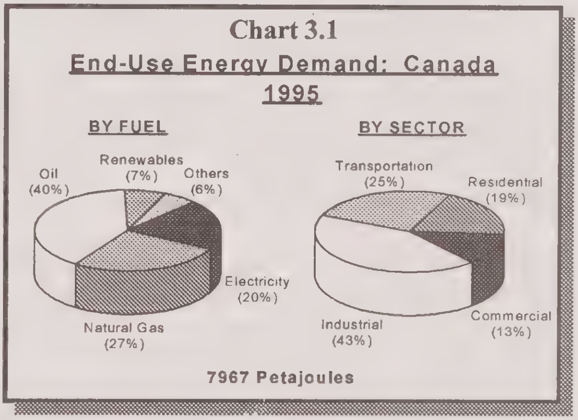
- the VCR, in particular, is viewed as a mechanism which complements other initiatives and accelerates their take-up. The exceptions are the fossil fuel production, electricity generation, and non-energy VCR commitments which are the only initiatives in these sectors and are separately identified; and,

- all initiatives are assumed to remain in place (or be replaced by similar measures) and to continue to receive the same level of funding throughout the projection period.

Chapter 3

End-Use Energy Demand

This chapter provides projections and analysis for energy demand for the four principal energy using sectors[7]; residential, commercial, industrial and transportation. As shown in Chart 3.1, total demand by these sectors in 1995 was 7967 Petajoules[8]. By fuel, oil use accounts for the largest proportion followed by natural gas and electricity. The industrial sector is the largest consumer of energy followed by the transportation sector.



The long term energy demand projection is developed using the econometric Inter-fuel Substitution Demand (IFSD) model and process/end-use models. One of the main strengths of IFSD is that it emphasizes the relationship of energy demand, on a provincial basis, to economic and demographic variables such as prices, output, population and households. However, as with any econometric model, IFSD cannot adequately forecast technological improvements or changes other than those based on historical trends. In order to better

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7 End-use energy demand is a somewhat different concept than secondary energy demand. The main differences are in the industrial sector. For this sector, non-combustion use of energy (e.g. petrochemical feedstocks, lubes and greases) are included, but fossil fuel mining uses (i.e. oil sands, coal, etc..) are assigned to the fossil fuel producing sector (see chapter 4).

8 A Petajoule (10^{15} joules) is a measure of energy content and is employed to combine energy use of different fuels on a comparable basis. As an illustration, the City of Toronto consumes, on average, approximately 1.5 petajoules per day for its heating, lighting and transportation needs.

capture the penetration of new technologies, and the impact of standards and regulations, end-use or process models, maintained by the Energy Efficiency Branch, were used to complement the initial IFSD econometric forecasts. In addition, adjustments were made to the estimates following consultation with experts within NRCan, provincial governments, the petroleum industry and electricity and natural gas utilities.

3.1 End-Use Energy Prices

Consumer energy prices are a crucial determinant of both the level and composition of secondary energy demand. Translating the crude oil and natural gas wellhead price projections to the consumer level requires assumptions concerning a variety of charges - transportation, refining and distribution margins - and commodity taxes. Usually, these charges and taxes must be specified on a regional basis.

In almost all cases, we have adopted conservative assumptions concerning the trends in transportation, refining and distribution margins, namely that they increase only by the rate of inflation. Concerning commodity taxes, it is assumed that the rates for all applicable ad valorem taxes - most provincial fuel taxes and the GST - remain constant. No new energy taxes are assumed for the reference scenario.

Important features of the methodology used to calculate consumer prices for refined petroleum products (RPPs), natural gas and electricity and the results are provided below.

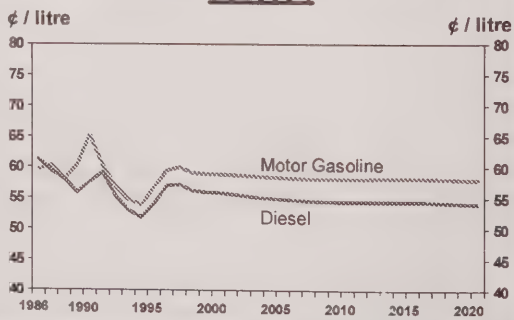
Refined Petroleum Product Prices

Domestic oil prices are calculated on the basis of WTI prices at Cushing (see chapter 2) adjusted for exchange rate, quality and transportation costs to determine an equivalent crude price at Edmonton, Montreal, Toronto and Halifax. The Canadian costs of crude oil are then translated into petroleum product prices, with the appropriate taxes for each province.

As shown in Chart 3.2, the prices of motor gasoline and diesel, which are directly tied to crude oil prices, rose in 1996, and are assumed to remain relatively stable through to 2020. The projections incorporate the impact of

Chart 3.2

Transportation Fuels: End-Use Prices ($1995)



increased investments and operating costs, incurred to meet the proposed regulations[9] on gasoline and diesel formulations, pursuant to the Canadian Environment Protection Act. Specifically, we have assumed that refiners achieve limited pass-through of 0.7 and 0.5 cents per litre of gasoline and diesel respectively to partially recover these costs.

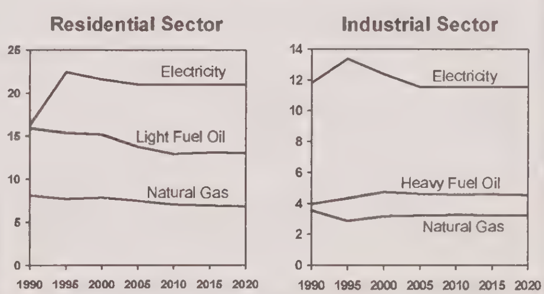
Inter-Fuel Competition

Energy end-use prices (i.e., prices at the burner tip) vary considerably by sector. Chart 3.3 displays end-use prices by fuel for the residential and industrial sectors at the national level. These prices are adjusted for the energy efficiency content of each fuel. It should be noted that market shares are sensitive to relative price changes and not to absolute changes in price levels.

In the residential sector, prices for all fuels decrease slightly at roughly the same rate. Light fuel oil and natural gas remain more competitive than electricity throughout the projection horizon. In some instances, technological changes and relative capital costs of alternative systems can favour the use of electricity. But, the high price of electricity suggests that there will be only limited substitution towards this fuel.

Chart 3.3

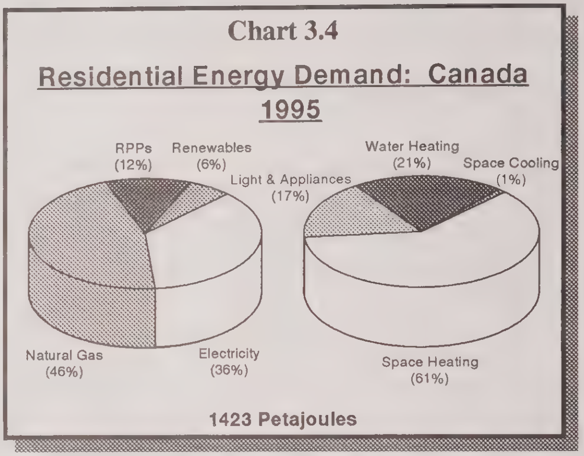
Inter-Fuel Price Competition
($1995/GJ)



In the industrial sector, the price of electricity decreases moderately to reflect Ontario's price announcement discussed in chapter 2. Due to the high degree of substitution between heavy fuel and natural gas in the industrial sector, heavy fuel prices track closely natural gas prices and hence, prices for both these fuels are projected to be almost identical over the projection horizon. Overall, the fuel price projection indicates that inter-fuel competition will continue to be relatively intense as it has been since 1985.

9 These include the removal of MMT, reduced RVP levels, reduction in benzene levels and removal of sulphur from on-road diesel.

3.2 Residential Sector



The residential sector represents slightly more than 20 percent of total end-use demand. As shown in Chart 3.4, demand in the residential sector includes space heating and cooling, water heating, appliances and lighting. Space heating is the major use, accounting for over 60 percent of total residential energy consumption, which also explains the dominance of natural gas as the preferred fuel.

Major fluctuations in the weather can result in large swings in yearly residential energy use. The mild weather of 1990, for example, caused energy demand in that year to be almost 40 PJ lower than it would have been under normal weather conditions. For the projection, we are assuming a continuation of the average trend in temperature observed over the period 1980-1995. Neither short term fluctuations nor a possible long term warming trend has been incorporated[10].

The most important factors underpinning the long term residential energy demand projection are changes in the housing stock, real disposable income per household, energy prices and energy efficiency initiatives. Expected trends for the first three determinants are shown in Chart 3.5. Household growth slows from the past rate of almost 2 percent per year to slightly above 1 percent, while household incomes remain relatively stable.

The average energy price, which in the early 1990s grew at almost 4 percent per year because of increases in electricity rates, is expected to remain relatively flat for the forecast period.

10 While we recognize the possibility of a long term warming trend associated with the greenhouse effect, the evidence concerning its regional consequences for Canada is not yet clear. Natural Resources Canada is participating with Environment Canada and the U.S. Government in a Canada Country Study: Climate Change Impacts and Adaptation.

Energy efficiency initiatives play an important role in leading to a reduction in residential energy demand. Of the more than 70 quantifiable federal, provincial and municipal initiatives directed to this sector, over half are information programs while the remainder are regulations, R&D, and financial incentives. These initiatives include:

Chart 3.5

Residential Energy Demand

	1990/ 1995	1995/ 2000	2000/ 2010	2010/ 2020	1995/ 2020
Total Demand [1]	1.2	-0.4	-0.6	0.4	-0.2
Energy Intensity [2]	-0 9	-1 3	-1 8	-1.0	-1 4
Key determinants:					
- Household	1.9	1.3	1.2	1.4	1.3
- Household Income	-1.4	-0.2	0.6	0.8	0.5
- Real Energy Prices	3.8	-0.2	-0.2	0	-0.1

[1] Adjusted for weather fluctuations.
[2] Energy demand per household.

- minimum energy efficiency regulations for new equipment - resulting from the Energy Efficiency Acts of Ontario, Quebec, New Brunswick, Nova Scotia, British Columbia and Canada;

- building codes for new construction, such as The National Energy Code for Housing; and,

- voluntary initiatives for existing housing such as Manitoba's Home Energy Savers Workshops and NRCan's Home Energy Retrofit Initiative.

The impact of the initiatives in the residential sector leads to significant improvements in the thermal energy requirements for houses, as well as the energy efficiencies of equipment in all major residential end-uses (furnaces, appliances, water heaters, air conditioners and lighting). Chart 3.6, which shows the end-use intensities of selected new housing and appliances over the period from 1990 to 2020, illustrates this trend. As a result, the associated energy efficiency improvements in equipment stock are significant, for example, the efficiency of the stock

Chart 3.6

Selected Residential End-Use Intensities
(Gigajoules/Household)

	1990	1995	2000	2020	% Change 1995/2020
Space Heating (Ontario - gas)	44.8	35.5	32.5	27.1	-24
Electric Water Heaters	19.6	17 1	15 3	13 4	-22
Refrigerators	3 8	2.1	1 4	1 4	-33
Freezers	2 2	1 2	0 9	0 9	-25

of natural gas furnaces increases from 66 percent in 1995 to 91 percent in the year 2020 - almost a 40 percent improvement. Similarly, the average per unit energy consumption of the stock of refrigerators is 60 percent lower in 2020 than in 1995.

Chart 3.7

Residential Energy Demand: Canada

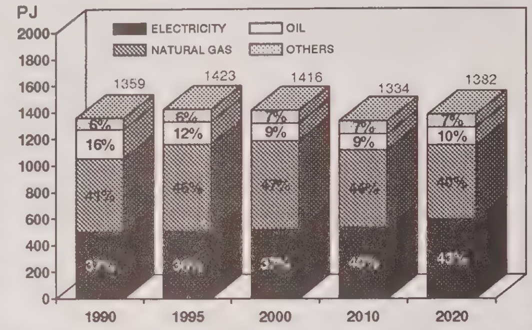
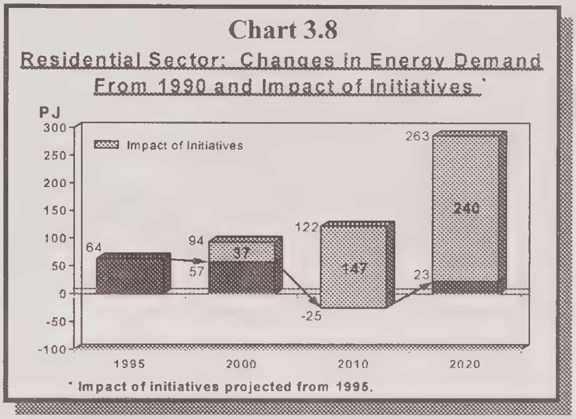


Chart 3.7 provides the trend in residential energy demand by fuel to 2020. Demand is expected to increase moderately during the 1990s and then to decline through the next decade, reflecting significant efficiency improvements in space and water heating and appliance stock turnover. During the last decade of the forecast period, the growth in the number of households outweighs stock efficiency improvements, leading to modestly growing demand for energy. It is worth noting, however, that residential energy demand in 2020 is 3 percent lower than in 1995.

Fuel shares in the residential sector change significantly over the forecast period. The market share for electricity is projected to increase from about 36 percent in 1995 to 43 percent by 2020, while the share for natural gas falls 6 percentage points over that same period. This shift reflects major efficiency improvements in space heating and to a lesser degree in electrical appliances. As a result of regulations, new furnaces are significantly more efficient and the housing stock has lower thermal requirements. Consequently, demand for gas, which is the dominant fuel for space heating, declines while electricity use increases, albeit at a fairly slow pace. This trend is further reinforced by relatively stable real electricity prices (in fact, real electricity prices decrease in Ontario up to the year 2005), and the increased use of consumer electronics, such as personal computers.

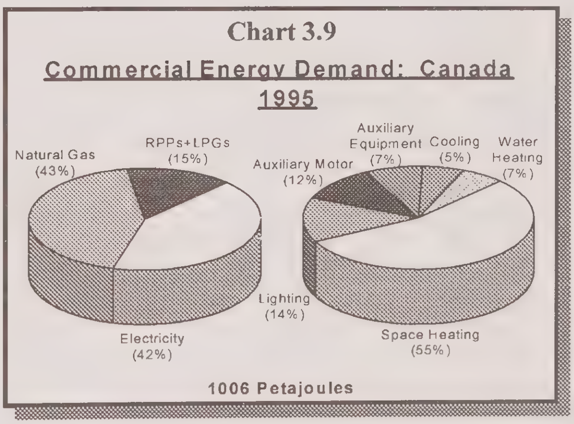
Energy intensity, defined as energy demand per household, declines at an average rate of 1.4 percent per year. This improvement outpaces by far the experience over the last 10 to 15 years (0.9 percent). Much of the responsibility for this improvement is due to the impact of initiatives, in particular the introduction of new standards, more stringent existing standards, and the resulting changes in the housing and appliances stock. This impact is illustrated in Chart 3.8. Without initiatives, demand would have increased by almost 100 PJ between 1990 and 2000 and by over 250 PJ between 1990 and 2020. In 2020, the initiatives almost counterbalance the projected increases resulting in a very small growth in demand relative to the 1990 level.



3.3 Commercial Sector

The commercial sector is comprised of two major building types: commercial and institutional. Commercial and institutional buildings include office, retail establishments, large apartment buildings, hotels, motels, restaurants, warehouses, recreational buildings, schools and hospitals.

As shown in Chart 3.9, the commercial sector consumed in 1995 about 1000 PJ, representing 13 percent of total direct end-use demand. On a fuel basis, natural gas accounts for 43 percent of total energy consumption followed closely by electricity at 42 percent. End-uses in the commercial sector are similar to those in the residential sector with space heating being the largest single component (55 percent), followed by lighting (14 percent) and auxiliary motors (12 percent).



Energy demand in the commercial sector is driven by capital stock growth, real energy prices and initiatives. As shown in Chart 3.10, total energy demand in the commercial sector is expected to grow, on average, at about 0.8 percent per year, reflecting a slower growth in capital stock, from 2 percent in the 1990s to 1.6 percent post 2010, and a similar deceleration in the rate of energy intensity improvement of the stock. The pattern in energy intensity is influenced both by energy efficiency improvements in new buildings and the turnover of capital stock. The former is driven by federal, provincial and municipal energy efficiency initiatives. Some of the initiatives incorporated in the commercial energy demand projections are:

Chart 3.10

Commercial Energy Demand

	1995/2000	2000/2010	2010/2020
	Average Annual Growth Rates (%)		
Total Demand	0.3	0.9	1.1
Energy Intensity	-1.7	-1.0	-0.5
Key Determinants:			
• Capital Stock	2.0	1.9	1.6
• Real Energy Prices	1.0	1.2	1.3

- National Energy Codes for Buildings;
- lighting regulations;
- the Federal Buildings initiative and similar provincial programs; and,
- minimum efficiency standards for energy using equipment.

As displayed in Chart 3.11, these initiatives, principally more stringent standards for new buildings and equipment, are expected to be put in place within the next few years. Post 2000, only minimal changes to the National Energy Codes for Buildings and Houses, and lighting regulations are envisioned. As a result, the post 2000 energy intensity movements are largely a function of expansion of the capital stock. One reason that this expansion is relatively slow is the minimal growth in

Chart 3.11

Selected Commercial End-Use Intensities - Quebec Office Buildings

	1995/2000	2000/2020
	Average Annual Growth Rates (%)	
Space Heating	-3.2	-0.1
Lighting	-5.4	0.0
Cooling	-3.2	-0.1
Motors	-0.6	0.0

the public administration sub-sector. The stock of buildings devoted to public administration is expected to remain at current levels, reflecting government restraint and downsizing programs.

Chart 3.12 provides the trends in commercial energy end-use. As noted earlier, the growth is approximately 0.8 percent per year, so that by 2020 demand is expected to be 23 percent higher than in 1995. Major fuels maintain their positions because relative fuel prices are expected to remain constant over the forecast period. As shown in Chart 3.13, the impact of energy efficiency initiatives in the commercial sector is more modest than in the residential sector reflecting the longer service life of commercial equipment. Initiatives are expected to lower energy demand by about 15 PJ in 2000 and 89 PJ in 2020. The latter represents about 17 percent of the growth in demand since 1990.

Chart 3.12

Commercial Energy Demand: Canada

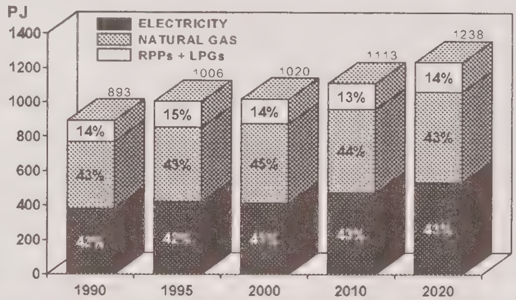
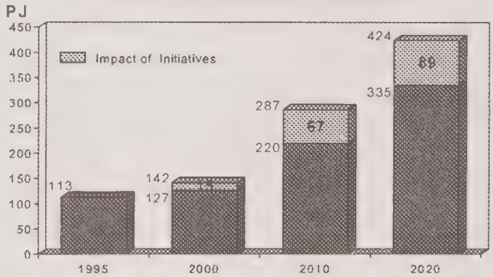


Chart 3.13

Commercial Sector: Changes in Energy Demand From 1990 and Impact of Initiatives *



* Impact of initiatives projected from 1995.

3.4 Industrial Sector

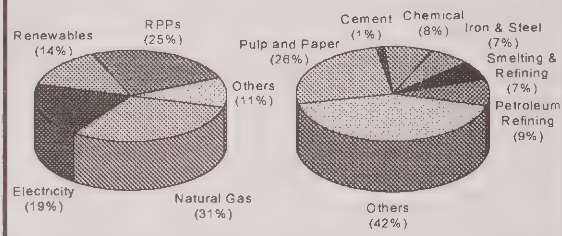
The industrial sector,[11] the largest energy using sector accounted for 43 percent of total end-use demand in 1995, includes all manufacturing industries, as well as forestry, construction and mining. As shown in Chart 3.14, natural gas accounts for the largest share followed by electricity. Renewables, chiefly biomass used by the pulp and paper industry, also represent

11 Unless otherwise specified, energy demand from non-combustion uses of energy (feedstocks, asphalt, etc.) and from fuel use in petroleum refining are included in the industrial sector. Fuel use by oil and gas producers in the mining sector is excluded from the industrial sector and included in the fossil fuel production category.

a significant share. Six energy intensive industries - pulp and paper, iron and steel, smelting and refining, chemicals, petroleum refining and cement - make up about 60 percent of total industrial energy demand even though their share of industrial production is only 15 percent. Industrial energy use is, therefore, not only influenced by overall changes in industrial production but also by changes in the composition of that production. To capture this crucial relationship, the analysis is disaggregated into 10 sectors. The key drivers include real gross output, energy prices, investment, capital productivity and initiatives to improve energy efficiency.

Chart 3.14

Industrial Energy Demand: 1995



3425 Petajoules

The impact of the initiatives in the industrial sector is more voluntary than mandatory in nature. In the short term, the initiatives incorporated in the outlook reflect the Minister's Advisory Council on Industrial Energy Efficiency (MACIEE) commitment of a 1 percent per year reduction in energy intensity until the year 2000. MACIEE provides direction for the Canadian Industry Program for Energy Conservation (CIPEC), which assists industry to develop energy-efficiency targets and action plans at a sectoral level. Over the longer term, the initiatives for the energy intensive industries reflect the achievement of 50 percent of the economic potential for energy efficiency improvements[12].

Outlook by Industry

Chart 3.15 summarizes the growth rates for output, energy demand and energy intensity for the 10 sectors. The sectors are grouped in two categories - energy intensive and less energy intensive. Below is a brief discussion of the highlights for individual industries.

12 Mark Jaccard and Associates, Industrial Energy End-Use Analysis and Conservation Potential in Six Major Industries in Canada, report commissioned by Natural Resources Canada.

Chart 3.15
Gross Output, Energy Demand and Energy Intensity by Industry, 1995-2020

	Gross Output [1]		Energy Demand		Energy Intensity (Demand /Output)	
	1995/ 2000	2000/ 2020	1995/ 2000	2000/ 2020	1995/ 2000	2000/ 2020
	Annual average growth rates					
Pulp & Paper	1.2	1.8	0.5	1.4	-0.7	-0.4
Iron & Steel	1.3	1.1	0.2	0.3	-1.1	-0.8
Chemicals [2]	2.7	2.6	1.7	2.0	-1.0	-0.6
Smelting & Refining	1.5	2.1	0.7	1.5	-0.8	-0.6
Cement	1.5	2.0	0.7	1.5	-0.8	-0.6
Petroleum Refining	0.5	1.0	-0.9	1.0	-1.4	0.0
Energy Intensive Industries (Total)	**1.3**	**1.9**	**0.6**	**1.4**	**-0.7**	**-0.4**
Other Manufacturing	4.7	2.3	3.3	1.2	-1.4	-1.1
Mining	1.2	0.9	0.6	0.7	-0.6	-0.1
Construction	3.2	2.2	2.5	1.4	-0.6	-0.8
Forestry	0.5	1.5	-0.3	0.9	-0.8	-0.5
Less Energy Intensive Industries (Total)	**4.0**	**2.2**	**2.2**	**1.0**	**-1.7**	**-1.1**
Total Industrial (RDP)	**3.1**	**2.0**	**1.2**	**1.3**	**-1.8**	**-0.7**

(1) **Growth rates for energy intensive, less energy intensive and total industry reflect changes in gross output measured in $1986.**
(2) **Excludes non-combustion energy demand (i.e. petrochemical)**

Pulp & Paper

World demand for pulp and paper products is expected to increase by 3.0 percent per year over the next ten years. However, Canada is unlikely to be supplying this growth in demand because of the high cost of recycled paper and the constraints on the supply of virgin fibre. As a result, moderate export and domestic demand growth, coupled with slower import growth, will yield output growth of about 1.7 percent per year.

In terms of energy efficiency, the increased employment of mechanical pulping technology and recycled paper and the use of more efficient motors and auxiliary equipment explain most of the energy intensity declines in this industry. Offsetting these efficiency gains, however, is the increased use of biomass (eg. hog fuels or pulping liquor), a less efficient fuel but one which does not contribute to net greenhouse gas emissions. Over the period 1995 to 2020, energy intensity decreases at an annual rate of only 0.4 percent including biomass versus 1.0 percent excluding biomass.

For the pulp and paper industry, total energy demand is expected to increase by approximately by 310 petajoules or 35 percent between 1995 and 2020. Of this amount, conventional fuels will account for 40 percent of the increase and renewables for 60 percent.

Iron & Steel

According to industry experts, Canadian iron and steel producers will likely experience growth in the range of 1.0 to 1.5 percent per year over the forecast period. The reasons are related both to a slower domestic demand (moderate growth in the construction and automotive industries) and to a limited penetration of Asian and other markets (resulting from the excess steel making capacity worldwide and the relatively high cost of shipping).

On the intensity front, the increased processing of recycled materials and, thus, the use of mini-mills, will account for the lion's share of the intensity decreases in the iron and steel industry. In fact, capacity from integrated plants is expected to remain unchanged at 1995 levels over the entire forecast period.

Energy demand in the iron and steel industry is projected to be only 7 percent higher in 2020 relative to 1995. In light of the stagnant production of virgin steel, coke and coke oven gas use will remain relatively constant over the forecast period. By contrast, a significant increase in electricity demand is expected as a result of the increased proportion of production from mini-mills.

Chemicals

World demand for chemical products is expected to grow by slightly more than 4.0 percent per year over the next ten years. The Canadian chemical industry is highly international with 50 percent of production exported and 50 percent of domestic demand satisfied by imports. The industry is in a strong competitive position in terms of capital, input and labour costs. As a result, Canadian chemical production growth is expected to be somewhat more robust than other energy intensive industries. The outlook for chemical production is essentially driven by declining imports. Over the forecast period, domestic production is projected to grow by 2.8 percent per year, exports by 1.7 percent and imports to decline by 1.7 percent.

Energy intensity declines stem chiefly from more efficient new capital stock, from the use of more efficient process technologies and more efficient motors and auxiliary equipment. These factors result in intensity declines averaging about 1.0 percent per year to 2000 and 0.6 percent thereafter. The production and intensity projections suggest that chemical energy demand will increase by roughly 60 percent over the next twenty five years.

Smelting & Refining

In the smelting and refining industry, aluminum is by far the most important sub-sector representing nearly 60 percent of overall production. According to major Canadian aluminum producers, new smelting capacity will be constructed in Africa, the Middle East, Latin America and Australia rather than in this country. Unlike the situation for steel, recycled aluminum is not expected to play a key role in terms of aluminum supply. The Outlook calls for essentially constant aluminum output between 1995 and 2000 and for moderate annual growth, of 1.2 percent, thereafter. More favourable growth is expected for the smelting and refining of other metals such as copper, zinc and nickel. As a whole, production in the smelting and refining industry is projected to be 65 percent higher in 2020 relative to 1995.

Because of relatively slow capital turnover in the aluminum industry, efficiency improvements will come mainly from the penetration of more efficient cells (a technology for the transformation of bauxite to alumina), motors and auxiliary equipment. As a result of modest production growth, coupled with the expected energy efficiencies, energy demand for this industry will increase by about 40 percent over the next twenty five years.

Cement

Consistent with the views underlying the Canadian Cement Council submission to the Voluntary Challenge and Registry, the Outlook calls for moderate growth in cement production of 1.8 percent per year over the forecast period.

It is expected that the industry-wide shifts in cement kiln technology, from the less efficient wet process to the more modern dry and preheater/precalciner processes, will continue. This shift and other changes, such as further improvements in the processing of clinker and the replacement of Portland cement in concrete by materials such as fly ash, will result in energy intensity declines of 0.6 percent per year over the forecast period. The combined effects of production and technologies result in an increase in energy use of slightly less than 40 percent between 1995 and 2020.

Petroleum Refining

The petroleum refining industry is expected to experience sluggish growth up to 2000 and modest growth thereafter. The factor constraining production will come from the demand side and not from supply. Domestic gasoline and diesel demand is expected to grow by about 1.0 percent per year (see Section 3.5).

As noted earlier, the industry is expected to invest substantially to meet requirements of the new regulations under the Canadian Environment Protection Act (CEPA). These investments, coupled with new technologies to reduce process heat requirements, will produce some intensity declines over the medium term. In line with the production and intensity forecasts, energy demand for the petroleum refining industry will grow well below historical trends.

Less Energy Intensive Industries

The less energy intensive industries consist of mining (excluding fossil fuel production), construction, forestry and "other" manufacturing (i.e manufacturing industries exclusive of the energy intensive group). The "other" manufacturing sector accounts for the lion's share of energy demand -80 percent - within the less energy intensive industries. As displayed in Chart 3.15, other manufacturing is projected to experience significant output growth over the forecast period. Within this sub-sector, it is the least energy intensive industries - electronics, auto parts - which grow the fastest accounting for roughly 75 percent of output growth between 1995 and 2000, and 60 percent between 2000 and 2020.

For the most part, energy costs in the less energy intensive manufacturing industries represent only a small fraction of total costs and hence, energy efficiency improvements are often a by-product of efficiency gains from other factors of production. In order to capture these energy efficiency gains, it is assumed that intensity declines follow closely total factor productivity increases in this sector. The significant energy intensity declines for the non-energy intensive industries are the result not only of energy efficiency gains but also of a structural shift in production favouring the least energy intensive industries. Economic factors and energy efficiency initiatives account for roughly half of the intensity declines, while structural shifts in production explain the other half. By the year 2020, the output and intensity forecasts result in energy demand being almost 50 percent above 1995 levels.

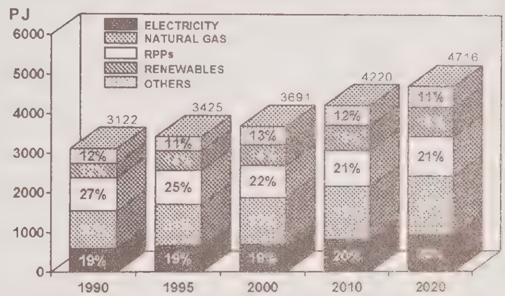
Overall Industry Outlook

As summarized in Chart 3.15, and shown graphically in Chart 3.16, total industry energy demand is projected to be 38 percent or 1300 PJ higher in 2020 relative to 1995. Demand by both energy intensive and less energy intensive industries is expected to grow at an annual rate of 1.3 percent over the 1995/2020 period.

It is interesting to note that, during the period 1995-2000, total industrial intensity declines by more than any of the individual industry intensities. This is due to a structural shift in the composition of energy demand and output growth. On the one hand, overall output increases because of the rapid growth, 4.0 percent, of the less energy intensive industries. On the other hand, total energy demand experiences only a relatively small increase, 1.2 percent, because of the very small growth in demand by the energy intensive industries. Together, this results in a re-weighting of the components of aggregate industrial energy intensity and, thus, in an overall intensity decline that is higher than for the individual industries.

Chart 3.16

Industrial Energy Demand: Canada

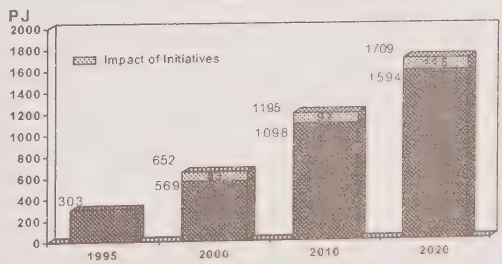


Despite an increase of nearly 38 percent in industrial energy demand over the period 1995-2020, the fuel shares are not expected to change substantially. Major fuels maintain their positions because relative fuel prices are expected to remain constant over the forecast period. For the long run, no major structural changes within the industrial sector are foreseen that would significantly alter fuel use patterns.

Chart 3.17 shows the impact of initiatives on industrial energy demand. Initiatives underpinning this outlook lower energy demand by 83 PJ in 2000 and by 115 PJ in 2020. The former number largely reflects the MACIEE commitment for a one percent annual improvement in energy efficiency. The long-term estimate for initiatives may, however, be too low. At the time of writing, industry has not yet committed to any targets for the post-2000 period.

Chart 3.17

Industrial Sector: Changes in Energy Demand From 1990 and Impact of Initiatives*

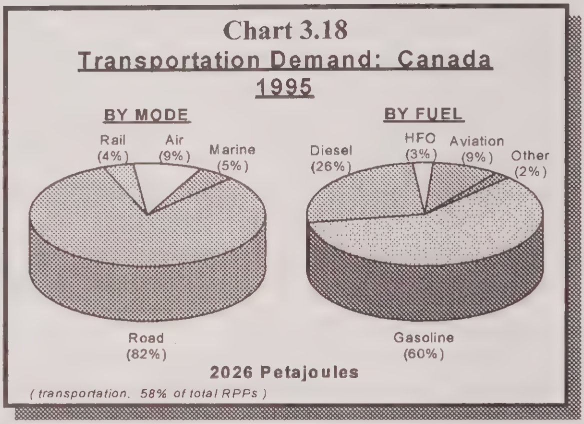


* Impact of initiatives projected from 1995.

3.5 Transportation Sector

Energy use in the transportation sector includes motor gasoline and alternate fuels for automobiles, diesel fuel for trucks and trains, turbo fuel and aviation gasoline for aircraft, and heavy fuel oil for ships.

As shown in Chart 3.18, total energy consumption[13] in this sector in 1995 was 2026 petajoules or 56 billion litres, of which approximately 82 percent was used for road transportation.



Road transportation

The main determinants of road energy demand are the stock of vehicles, the average fuel efficiency of the vehicle stock and the average distance travelled per vehicle. These determinants, in turn, reflect the influence of fuel prices (discussed earlier in this chapter), income and demographics as well as the effect of initiatives.

Economic factors underpinning the transportation outlook call for modest growth in personal disposable incomes - income per household declines in the early years, then grows very slowly thereafter. In terms of demographics, the number of households is projected to grow at slightly above 1.0 percent per year. An interesting point to note is the increasing share of the over-65 age cohort. By 2020, persons over 65 will represent 35 percent of the population, up from 22 percent in 1995. This aging of the population may have significant implications for vehicle ownership and distance travelled, as well as for air travel. This is an important area for further research.

13 Transportation energy demand includes farm motor gasoline, and aviation fuels used by public administration, commercial and other institutions.

The results also incorporate the impact of energy efficiency programs. There is a small number of initiatives aimed at the transport sector, mostly providing information. In the passenger vehicle segment, the majority of programs are aimed at influencing driving behaviour. One such initiative, the federal Auto$mart program, offers information to consumers on how to buy, drive and maintain a car to save money and to reduce fuel consumption. In the freight vehicle market, there is a mix of information, education and research and development programs focussed on improving operating and maintenance practices, improving load management and influencing vehicle purchase decisions. Other initiatives, such as the federal government's FleetWise program, are designed to enhance the penetration of alternative fuels.

The outlook for vehicle stock is illustrated in Chart 3.19. There is a wide variation in the expected growth in the stocks of different types of vehicles. Of all categories, passenger car stock is projected to grow at the lowest rate of 0.9 percent per year, increasing from 11 million in 1995 to 14 million in 2020. Car sales have been stagnant for the past 5 years. Furthermore, in this era of better-built vehicles, consumers tend to re-enter the market at a slower rate than historically.

Chart 3.19

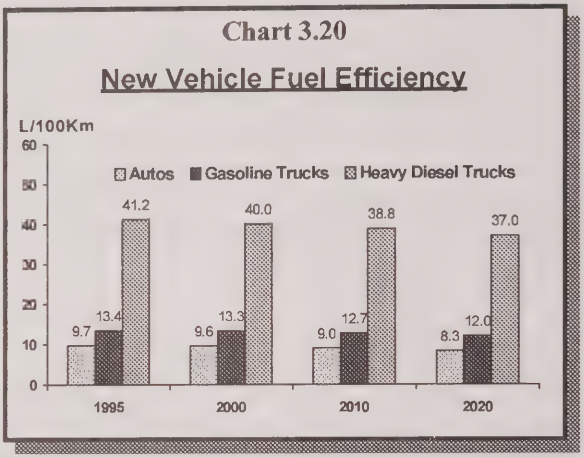
Vehicle Stock (Thousands of vehicles)

	1980	1990	1995	2000	2010	2020
Automobiles	9 650	10 470	11 350	11 440	12 250	14 000
Gasoline trucks	2 800	3 800	4 230	4 760	6 160	7 700
Diesel trucks	320	440	520	580	710	820
Total	12 770	14 710	16 100	16 780	19 120	22 520
Cars / Household	1.21	1.09	1.08	1.02	0.97	0.90
Light Vehicles / Household	1.56	1.48	1.48	1.44	1.45	1.49

Another factor leading to a slower growth in automobile stock is the shift from large cars to minivans and sport utility vehicles. Annual sales of minivans and sport utilities have risen sharply, from 9,000 units in 1982 to over 190,000 in 1994, so that they now represent about 25 percent of the stock of light gasoline trucks and vans. This shift, together with the stimulus of a growing economy, will lead to a faster pace of growth of 2.4 percent in the stock of gasoline trucks and vans. A point to note is that while automobiles per household is projected to decline, the average number of light vehicles (automobiles and gasoline trucks) per household remains relatively stable.

The stock of diesel trucks will increase by 300 thousand units over the period 1995-2020. This is mainly a consequence of strong growth in trucking activity, averaging 3 percent per year over the forecast period, and the current high level of capacity utilization of the fleet.

Trucks have garnered an increasing share of the freight market over the past decade, and this trend is expected to continue with increased Canada-United States trade, the repeal of the Western Grain Transportation Act and the dismantling of inter-provincial trade barriers.



The fuel efficiency of new vehicles sold in Canada is perhaps the most critical assumption underlying the projection of road transport demand. Fuel prices will have little impact on technology improvements and consumer choices, as fuel costs continue to represent a decreasing share of vehicle operating costs. The likely fuel efficiency trend in the U.S. is an important consideration in developing this assumption because of the integrated nature of the North American market. We are assuming that the U.S. Administration will not introduce a new round of Corporate Average Fuel Economy (CAFE) standards. As an alternative, the U.S. government and the three major North American car manufacturers have entered into an agreement, known as the Partnership for a New Generation of Vehicles, to cooperatively develop a prototype super fuel efficient car (rating of 3.5-L/100Km) within a decade. It seems unlikely, however, based on the U.S. Department of Energy projection[14], that this program will be a major factor over the forecast horizon.

In the absence of significant regulatory activity, the product plans of automobile manufacturers indicate continued enhancements of the performance characteristics of many popular models. This suggests little in the way of fuel efficiency gains in the near term. However, Memoranda of Understanding[15] between the Federal Government and domestic and import vehicle manufacturers will foster the development of strategies to improve vehicle fuel efficiency. In the longer term, therefore, these changes and the effect of program initiatives will lead to modest efficiency gains for new vehicles. As indicated in Chart 3.20, the efficiency of new autos is expected to improve at a slightly faster rate of 0.6 percent per year, compared to 0.4 percent per year for gasoline trucks and heavy diesel trucks.

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14 The most recent projection of the US Department of Energy assumes new car fuel efficiency improvement, of 0.9 percent per year over 1995 to 2015. See Energy Information Administration, Department of Energy, Annual Energy Outlook 1997, December, 1996

15 Agreements on motor vehicle efficiency have been signed with Motor Vehicle Manufacturers Association of Canada in November, 1995 and with the Association of International Automobile Manufacturers of Canada in February, 1996.

Average travel for the different types of vehicles is shown in Chart 3.21. The average distance travelled per vehicle is a function of economic, social and demographic changes. In the case of passenger cars, declining cost of driving and the closing of the gap in the number of kilometres travelled by male and female drivers will have a positive influence on usage rates. However, the adoption of telecommuting on a wider basis will have the opposite effect on business related travel. In sum, all of these influences will lead to a marginal increase in the average distance travelled, 0.2 percent per year.

Chart 3.21

Average Annual Kilometres Driven

	1980	1990	1995	2000	2010	2020
Cars	17610	20630	21580	21720	21980	22510
Gasoline trucks	23610	21480	21230	21060	21100	21370
Heavy Diesel trucks	67530	78340	95180	102100	100300	100100

The increasing share of minivans and sport utility vehicles in the gasoline truck segment contributes to the stabilization of average distance travelled. With respect to diesel trucks, the average usage rate was relatively high in 1995 because strong economic growth and a boost in transborder traffic caused significant increases in freight volumes. Over the early years of the forecast period, the pace of growth in average distance travelled slows, reflecting the recovery in truck sales. Moreover, average distance is projected to follow a declining trend post-2000 owing to the increased use of computer technology, growth in intermodal cooperation, and the effect of government initiatives to educate the trucking industry on better driving practices.

As shown in Chart 3.22, alternative fuels are not expected to make significant advances in the road sector, accounting for about 60 petajoules - 3.0 percent of road energy use - in the year 2020. Although the contribution of these fuels will remain small, use will continue to expand, increasing by about 30 percent from 1995 to 2020.

Chart 3.22

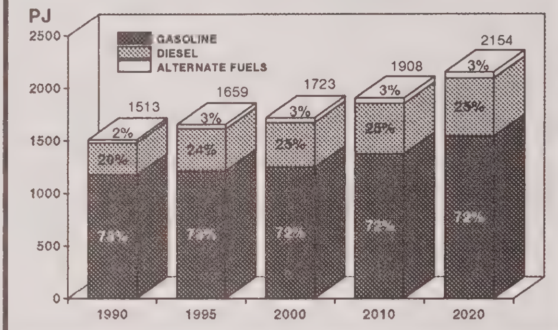
Alternative Transportation Fuels

	1980	1990	1995	2000	2020
	Petajoules				
Propane	2	26	33	35	44
Compressed Natural Gas	0	3	8	8	10
Ethanol	0	0	1	2	2
Electricity	2	3	3	3	3
Total	4	32	45	48	59

Several initiatives, sponsored by both governments and utilities, are in effect to enhance the penetration of alternative fuels. One example is the "FleetWise" initiative which commits the federal government to substitute 75 percent of its fleet with alternative fuel vehicles by 2004, where feasible and cost-effective. A second example is NRCan's work with Ballard Power Systems Inc. to further develop fuel cell technology.

Chart 3.23

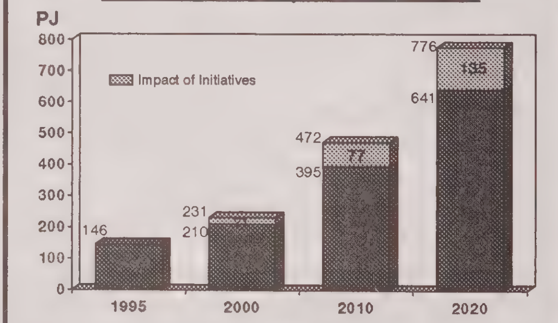
Road Transportation Energy Demand: Canada



Propane will continue to be the preferred option over compressed natural gas since it is the most economic alternative. The planned expansions of domestic ethanol supply (a new Ontario plant comes on stream in 1999 and others in Quebec and Ontario are under consideration[16]) will foster increased use of ethanol as a blend with gasoline. Competitive price pressures from the traditional fuels will, however, restrict the cost-advantage of switching to alternative fuels. Other barriers to their wider use include the lack of distribution infrastructure, high production costs for factory manufactured models and rising conversion costs. These barriers will make these fuels mainly attractive to high mileage vehicles and some specific niche markets.

Chart 3.24

Changes in Road Transportation Energy Demand From 1990 and Impact of Initiatives *



* Impact of initiatives projected from 1995.

In summary, road energy use is expected to grow at 1.0 percent per year, increasing by 28 percent from 1659 petajoules in 1995 to 2154 petajoules by 2020. Gasoline growth is less than diesel for the remainder of this decade, but then increases at a similar rate of 1 percent in the post-2000 period. Between 1995 and 2020, annual gasoline consumption is projected to rise 27 percent while diesel increases 38 percent.

[16] Enviroline, Vol. 8, No.5, pg.3, February 1997.

The impact of initiatives, which are almost exclusively focused on the road sector, is illustrated in Chart 3.24. It should be noted that this portrayal does not capture initiatives such as FleetWise which focus on fuel switching. Energy efficiency initiatives become increasingly effective over time with stock turnover. In the absence of these initiatives, transportation energy demand in 2000 would be 21 petajoules higher. By 2020 the initiatives impact grows to about 135 petajoules.

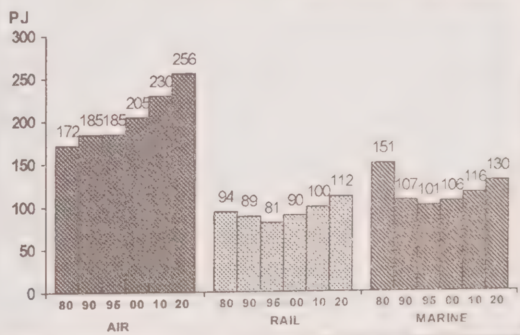
Air, Rail and Marine Transportation

Between 1990 and 1994, the demand for aviation fuels declined by 7 percent. In 1995, however, it rebounded to the 1990 level, as economic recovery stimulated both business and leisure travel. Transport Canada projects growth in air travel of 3.8 percent per year, at least until 2007. Factors contributing to this growth include greater leisure travel of the elderly segment of the population, and the increase in scheduled transborder services generated by the Open Skies Agreement between Canada and the United States. This growth occurs despite evidence that business travel is increasingly more price-sensitive and open to telecommunication alternatives.

Even with this significant increase in air travel, the demand for aviation fuels, as shown in Chart 3.25, is expected to grow only moderately at 1.3 percent per year over the forecast period. Load factors, which already increased as a result of industry restructuring, are assumed to improve modestly over the forecast period. The major moderating factor will be the acquisition of new more fuel efficient aircraft, which is expected to lead to an average aircraft fuel efficiency of 2 percent per year.

Chart 3.25

Other Transportation Demand: Canada



As also shown in Chart 3.25, rail demand is projected to increase annually by 1.3 percent from 1995 to 2020. In response to competition, the rail sector undertook major rationalization of its networks over the last decade, introducing higher capacity equipment and increasing the weight of average carload by over 6 percent. As a result, the use of all inputs, including fuel, has been reduced. Over the forecast period, rail fuel demand is expected to grow as the pace of rail productivity improvements slows and rail freight tonnage increases in response

to the growth in industrial production and increasing use by shippers of rail/truck intermodal services. As reported in the 1994 Annual Review of the National Transportation Agency of Canada, linkages between truck and rail services will be promoted by technological advances in intermodal systems[17].

Growth in marine demand, at 1 percent per year between 1995 and 2020, stems from increases in marine tonnage and requirements generated by a growing leisure cruising industry. Marine tonnage gains will come chiefly from growth prospects in transporting iron and steel, forest and agriculture products and coal for electricity generation. Strong positive influences on grain exports are the reduction in European subsidies on grain production and growing exports of Canadian cereal crops to Asian countries.

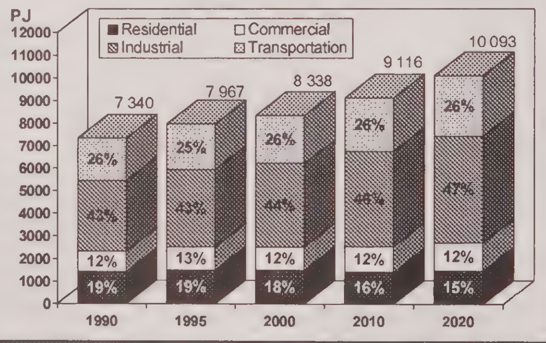
3.6 End-Use Energy Demand: Summary

This chapter summarizes the presentations for the four sectors - residential, commercial, industrial and transportation - to produce total end-use energy demand. It examines the overall projections by sector and by fuel, the trend in energy intensity and the impact of initiatives.

Chart 3.26 provides the projection for total end-use demand on a sectoral basis. Overall, end-use energy demand is anticipated, relative to 1995 levels, to increase by 5 per cent in 2000 and 27 per cent by 2020. These represent roughly one-half the growth rate in the economy.

Chart 3.26

End-Use Energy Demand by Sector



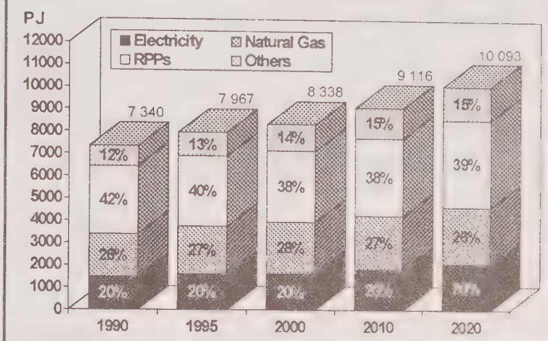
The share of residential energy demand is projected to decline over time, reflecting slower growth in the housing stock, the increasing effectiveness of initiatives and the replacement of older by new more efficient energy using equipment (e.g. furnaces). The commercial sector essentially retains its share for some of the same reasons cited for the residential sector. Growth of energy demand in the industrial sector is most pronounced. By 2020, demand in this sector will increase by 38 percent from 1995 levels. Transportation energy demand grows at about 1.1 percent per year maintaining its share over time.

17 National Transportation Agency of Canada, 1994 Annual Review-Transportation Trends & Issues.

Chart 3.27 displays the end-use demand projections on a fuel basis. Reflecting stable relative prices, the fuel shares do not change appreciably over time. Electricity, despite the more competitive environment, makes no significant inroads. Rather more surprisingly, natural gas does not increase its share. Although industrial demand for natural gas increases, this is offset by a declining demand in the residential and commercial sectors. This latter result is due largely to regulatory action - moving to mid and high efficiency furnaces and more energy efficient thermal shells for buildings. Refined petroleum products (RPPs) and other fuels (chiefly biomass in the pulp and paper industry) retain their positions throughout the projection.

Chart 3.27

End-Use Energy Demand by Fuel



As the comparison of end-use energy and economic growth, above, suggests, the energy intensity of the economy is declining over time. The intensity trends, by end-use sector, are shown in Chart 3.28. Overall, intensity is projected to decline by 1.3 percent per annum through 2000 and at a slightly lower rate thereafter. The commercial and industrial sectors contribute importantly to the overall decline. For the former, the driving factors are the initiatives, in particular higher efficiency standards for furnaces, water heaters and the introduction of energy efficiency components in building codes.

Chart 3.28

Energy Intensity Trends

	1995/2000	2000/2020
	Average Annual Growth Rates	
Transportation	-0.2	-0.7
Residential	-1.3	-1.3
Commercial	-1.7	-0.9
Industrial (1)	-1.8	-0.7
Total End-Use	-1.3	-1.2

(1) excluding non-combustion.

In the industrial sector, the explanation is more complex. The decline to 2000 reflects the commitment of a 1 percent reduction in energy intensity. In addition, the non energy intensive subsector of industry-electronics, auto and auto parts manufacture, other light manufacturing - which accounts for about 80 percent of output but only 20 percent of energy

use is expected to grow very rapidly.[18] The high levels of capital formation in these industries should produce energy efficiency improvements that roughly match overall productivity growth.

In the absence of initiatives, the energy demand for the end-use sector would have grown by 3340 PJ in 2020, 45 percent above 1990 levels.

The impact of initiatives directed at the residential, commercial, industrial and transportation sectors, reduce these levels by 167 PJ in 2000 and almost 600 PJ in 2020.

Chart 3.29

End-Use Sector: Impact of Initiatives

	1995	2000	2010	2020
	Petajoules			
Pre-Initiatives Level (changes from 1990)	626	1165	2165	3340
Impact of Initiatives:				
Residential		34	148	248
Commercial		29	67	89
Industrial		83	97	115
Transportation		21	77	135
Post-Initiatives Level (changes from 1990)	626	998	1776	2753

18 Within this sub-sector, it is the least energy intensive industries - electronics, auto parts - which grow the fastest. This produces a further structural shift which will generate a decline in industrial energy intensity even in the absence of efficiency gains.

Chapter 4

Fossil Fuel Supply and Trade

This chapter provides the projection and analysis of fossil fuel supply and trade. The chapter is divided into two sections. The first presents the projections for crude oil and natural gas and the second covers coal.

4.1 Crude Oil and Natural Gas Supply and Trade

Canada's crude oil production is derived from three principal sources: conventional deposits (light and heavy) from the Western Sedimentary Basin; the oil sands (synthetic crude oil or SCO and bitumen); and, the frontier deposits (offshore). A substantial amount of Canada's crude oil production is exported. Canada also produces significant volumes of natural gas, about half of which is exported.

The Outlook projects increased Canadian oil production, mainly as a result of increased production from frontier areas and the oil sands. Supplies from these sources are expected to more than offset the slight decline projected for conventional oil production. Natural gas production, which has increased significantly since the mid-1980s is expected to continue to grow, from 5.3 Tcf in 1995 to almost 7 Tcf by 2020. Our analysis suggests that, for both crude oil and natural gas, Canada should have sufficient capacity to meet growing domestic and foreign demand. Canada will remain a net exporter over the entire forecast period.

The key assumptions on major projects, resource potential, investment and replacement costs underlying the results for crude oil and natural gas are outlined below.

Major Project Assumptions

Chart 4.1 provides a list of key assumptions with respect to major oil and natural gas development areas.

Chart 4.1

Oil and Gas Supply Projects Assumptions

Western Canada					
Oilsands-mining		1995-2020			280 to 450 mbd
- Expansions:					
		1996-2005			70 mbd
		2006-2010			50 mbd
		2011-2020			50 mbd
Oilsands in-situ		1995-2020			150 to 400 mbd
East Coast					
Oil	Cohasset-Panuke	end	1998	20 mbd	
	Hibernia	start	1998	135 mbd by 2000	
	Terra Nova	start	2001	80 mbd by 2003	
	Others	Hebron, Whiterose, Ben Nevis, etc. to maintain production at 200 mbd			
Gas	Sable Island	start	2001	250 mmcf/day	
Northern Canada					
	Beaufort Sea	no			
	Mackenzie Delta	no			

Oil Sands Projects

Technological improvements, market opportunities, and recent changes to the fiscal environment are the key factors influencing future oil sands development[19]. Operating costs are assumed to continue to decline, reaching $11.20 per barrel by 2002 and thereafter remaining at this level.

The Outlook does not assume new grass roots integrated mining projects. Instead, increased production is projected to come from expansions to the existing mine-based projects (i.e. Syncrude and Suncor). Between 1995 to 2005, synthetic crude oil production is projected to increase by 70 thousand barrels per day (mb/d), between 2006 to 2010 by an additional 50 mb/d and between 2010 to 2020 by another 50 mb/d.

New bitumen projects and expansions to existing operations such as Cold Lake, Primrose and Peace River are expected to come on stream by 2020 which will more than double bitumen production. Overall, total production from the oil sands is expected to reach 850 mb/d[20].

Except for the Husky and NewGrade upgraders, now in operation, no other stand-alone or refinery add-on upgrader projects are assumed over the projection period[21]. However, small field upgraders (or visbreakers) are expected to come on stream, raising the quality of the bitumen to pipeline specifications (from heavy to medium crudes) for a total capacity to 50 mb/d.

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19 The 1996 Budget provided favourable capital cost allowance treatment to expenditures on efficiency investments and environmental improvements for mining and in-situ oil sands projects. The budget also removed existing differing tax treatment between oil sands mining and in-situ projects.

20 This is near the low end of the range, projected by the National Task Force on Oil Sands Strategies, The Oil Sands: A New Energy Vision for Canada, The Alberta Chamber of Resources, Edmonton, Alberta, Spring, 1995.

21 The recently announced Shell SCO project of 120 mb/d by 2002 is not included in this analysis.

Frontier Developments

No major oil or natural gas projects are incorporated in this Outlook for the Beaufort Mackenzie Delta Region. The major constraint on oil development is that there are insufficient reserves to warrant field and pipeline development. In the case of natural gas, the price and supply scenario developed in this Outlook suggests that opportunities in the western basin would be much more attractive. There will, however, be some oil and gas development of the upper Mackenzie that could be linked to the Norman Wells - Zama pipeline.

Hibernia will be the main oil project on the East Coast. It is projected to come on stream in 1998 and reach 135 mb/d in 2000. Production is expected to plateau at this level until 2005 and then decline.[22] The Terra Nova project is expected to commence production in 2001 and reach a peak of 80 mb/d in 2003. As production from Hibernia and Terra Nova starts to decline, other offshore sources such as Hebron, Whiterose and Ben Nevis are assumed to be developed to maintain the overall offshore production at 200 mb/d.

The Sable Island natural gas project is assumed to begin production in 2001. Average annual production is estimated at 250 mmcf/day. The viability of this project is largely based on markets in the U.S. Northeast.

Reserves and Resource Potential

Apprising the size of the resource base is critical in developing oil and natural gas production projections. It is well known that Canada has vast hydrocarbon resources. Below, are brief discussions of Canada's oil and natural gas resource bases.

Chart 4.2 shows Canada's existing crude oil resources. There seems to be little question that Canada has considerable resources that will support the development of the

Chart 4.2

Crude Oil Reserves and Potential
(Million Barrels)

	Remaining Established Reserves	Commercial Resource Base
Conventional Areas	3,710	12,600
Reserve/Production (years)	7.6	26
Frontier	1,200	20,100
Oil Sands	3,615	306,520

Sources: ERCB, CAPP, and NEB.

22 The estimated rate of 135 mb/d of production includes an allowance for both planned and unplanned downtime - Hibernia Management and Development Company, The Hibernia Development: 1996 Update, July 1996.

synthetic and bitumen projects, the east coast offshore projects, and the conventional oil investments. The view is that technology will continue to improve recovery and reduce costs. Even without technological improvements, Canada has about eight years of proven conventional oil supply in the Western Sedimentary Basin and about 26 years of remaining potential.

Chart 4.3 shows Canada's remaining natural gas resources. The remaining proved conventional reserves in the Western Sedimentary Basin are estimated at 68 Tcf which yields a Reserve to Production ratio of more than 12 years. The remaining potential estimate suggests 40 years of supply from the Western Basin at the current rate of production.

Recent history shows a tendency for the potential to be revised upwards over time as new information becomes available and technologies improve. This is evidenced for both the U.S. and Canada. For example, as Chart 4.4 shows, the estimates of the Alberta Energy and Utilities Board (AEUB), formerly the Alberta Energy Resource Conservation Board, have increased by 250 percent over the estimates made in the 1960s and 70s.

Chart 4.3

Natural Gas Reserves and Potential
(Trillion Cubic Feet)

	Remaining Established Reserves	Remaining Potential
Conventional Areas	68	255(*)
Reserve/Production (years)	12.5	40
Frontier	25	270
Coal Seam	20	250-2600

* Based on the upper end of the range of the consultees vies (335 tcf) in the NEB1991 Enregy Supply/Demand Report.

Chart 4.4

Alberta's Ultimate Gas Potential

Year of Estimate	Tcf
1964	100
1973	110
1979	130 to 140
1985	150
1987	170
1992	200
1993 *	270

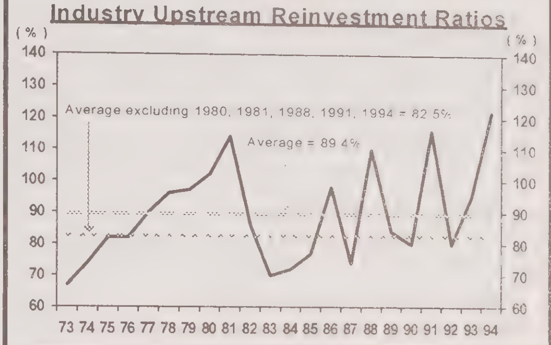
Sources: ERCB, Report 92-A, 1992.
* Sproule's estimate for 1993.

Investment

Profitable investment opportunities and available cashflow are the key drivers of energy investment. The Outlook assumes that the Canadian energy industry reinvestment (the ratio of investment to cashflow) will decline from 118 percent in 1994, to 82 percent by 2006 and will remain at this level thereafter. As shown in Chart 4.5, the 82 percent level is slightly

lower than the average in recent years. It is, however, closer to the average attained when the years of exceptionally high industry reinvestment are factored out. The logic of this removal is that in the years in which the reinvestment ratios changed significantly, there were drastic changes in policies and/or prices. The introduction of the National Energy Program in 1980 and the Gulf War in 1991 are two such examples. The 82 percent ratio also reflects the view that over the longer term the industry will be looking increasingly overseas for investment opportunities[23].

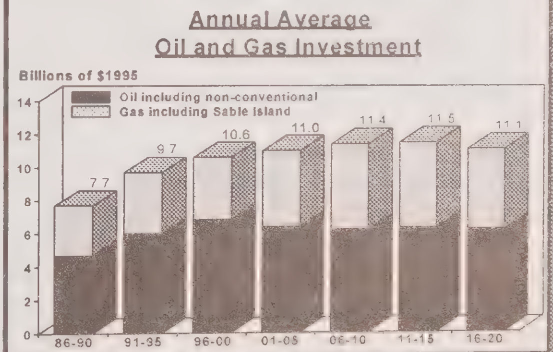
Chart 4.5



As shown in Chart 4.6, the Outlook projects investment in the range of $10-11 ($1995) billion per year over the forecast period. This represents a strong performance but not significantly above current levels.

In 1995, conventional oil related activity represented 57 percent of total investment. Oil related activity is expected to remain strong in the short term reflecting continued excess natural gas supplies and low natural gas prices. As the natural gas market tightens up however, conventional oil related activity is expected to fall to 43 percent of total investment by 2010 and to remain at this level until 2020.

Chart 4.6



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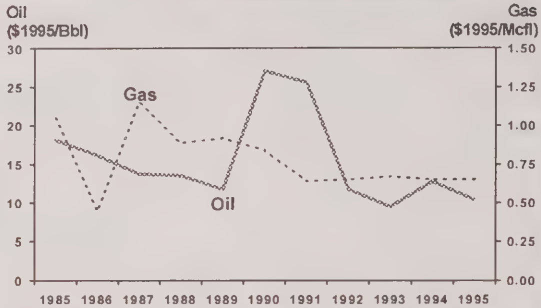
23 The 1994 Petroleum Monitoring Agency data indicated that the Canadian oil and natural gas industry directed about 8 percent of its investment to foreign opportunities.

Replacement Costs

Replacement costs are defined as the finding and development expenditures associated with one unit of oil or natural gas[24]. The average replacement cost for oil over the past ten years is provided in Chart 4.7. With the exception of the large spike in 1991 the trend for oil replacement cost has been gently declining since the mid 1980's. Natural gas replacement costs have, over the same period, decreased more steadily.

Chart 4.7

Oil and Gas Replacement Costs



Sources: ARC Financial Corporation.
Calgary Energy Consultants, Alberta Finding Cost Study 1996; and BC Finding Costs Study 1996

One of the primary reasons for the downward trend in oil replacement costs has been the development and application of new technologies. Technological advances in areas such as 3-D seismic, horizontal drilling, new in-situ recovery and transportation processes, polycrystalline drill bits, and natural gas process extraction are expected to continue to have a significant impact on costs and recoverable reserves. Chart 4.8 lists some of the technologies that are likely to impact replacement costs over the forecast period. Technological advances are also expected to affect the transmission, distribution, marketing and overhead costs.

Chart 4.8

New Technologies

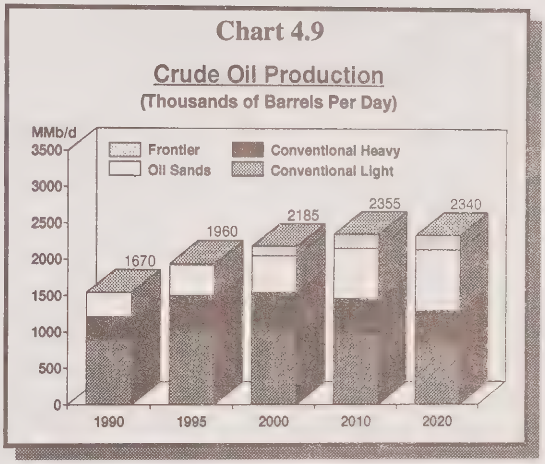
- Horizontal drilling
- 3-D Seismic
- New computer technologies
- New and improved materials (drill bits, drill pipes, motors)
- Hydrocyclones (Deoiling and Dehydration)
- Heavy oil emulsion upgrading process
- Steam assisted gravity drainage (SAGD)
- Froths and emulsions leading to alternative extraction processes
- Small field visabreakers
- Methyl cracking process (underway)
- Improved pumping technology (Augeoring)

24 Although replacement cost appears to be a fairly simple concept, there are several difficulties in calculating it. One of the major problems is allocating reserves when they are booked. The problem is further compounded by the aggregation on an industry basis.

The view is that technological advances and diffusion will lower finding and development costs of new reserve additions and increase recovery factors from existing reservoirs. For the Outlook, oil replacement costs are assumed to decline from the current level of $10.80/bbl to $8.10/bbl by 2002, while natural gas replacement costs are expected to remain at the current level of 65 cents per Mcf. This may be a conservative assumption but it reflects the likelihood of drilling occuring in the geologically more challenging foothills region of the basin[25].

Crude Oil Production and Trade Projections

Chart 4.9 summarizes the projections for total oil production from frontier, synthetic and conventional sources. The major points are as follows.



- Total oil production is forecast to increase from 1960 mb/d in 1995 to a minimum of 2350 mb/d in 2010 and to remain at that level to 2020.

- Total conventional oil production, predominately from the Western Sedimentary Basin, is projected to increase slightly by 2000 and then decline at an annual average rate of less than 1 percent per year. This slow decline over the longer term reflects our view that technological advances will continue to reduce costs and increase recovery from existing reservoirs.

- Conventional light oil production will decline from 1055 mb/d in 1995 to 860 mb/d by 2020, a decline of about 1 percent per year. Conventional heavy oil production is expected to continue to increase in the short term and to exceed 500 mb/d in 2000, and thereafter to decline slowly. Both Saskatchewan and Alberta heavy production have shown steady increases over recent years. The application of horizontal well technology in heavy oil reservoirs has been very successful, particularly in the case of Saskatchewan.

25 ARC's forecast of gas replacement costs for 1996 and 1997 are slightly below the 65 cents per Mcf.

- Production from the oil sands is projected to double to 850 mb/d by 2020. Synthetic crude oil and bitumen production are expected to expand by 60 percent and 160 percent, respectively, over the forecast period. By 2020, production from the oil sands is projected to account for 36 percent of Canada's total oil production (versus 20 percent currently).

- Production from Canada's frontier will increase from 20 mb/d in 1995 to 200 mb/d by 2010 and to remain at this level until 2020, thus accounting for 8 percent of Canada's total oil production.

Chart 4.10 summarizes Canada's projected crude oil production, consumption and trade position to 2020. Imports are projected to increase from 680 mb/d in 1990 to 1030 mb/d in 2020, an increase of about 50 percent. By the latter date, imports will account for about 60 percent of domestic consumption. Much of this increase in imports is related to the assumed reversal of the Sarnia-Montreal pipeline by 2000, with full capacity reversal by 2005. Exports will also increase sharply by 600 mb/d over the projection period to account for over 70 percent of production. Part of this increase is expected to come from the export of waxy crude from Hibernia and Terra Nova.

Chart 4.10

Summary: Oil Supply and Demand

	1990	1995	2000	2010	2020
	(Thousands of Barrels per day)				
Oil Production	1670	1960	2185	2355	2340
Imports (incl. Prod.)	680	735	895	990	1030
Total Supply	**2350**	**2695**	**3080**	**3345**	**3370**
Consumption	1445	1410	1465	1620	1790
Exports (incl. Prod.)	905	1285	1615	1725	1580
Total Demand	**2350**	**2695**	**3080**	**3345**	**3370**
Net Exports	225	550	720	735	550

Despite these massive changes in the gross trade flows, Canada will remain a net exporter of oil over the forecast period. Net exports should peak around 2010 at levels approaching 735 mb/d and then decline. Eastern Canada, in particular, will continue to rely almost exclusively on imports. These import and export positions suggest that the oil requirements of a portion of Ontario, all of Quebec and the Eastern provinces will be met from foreign sources and the Western provinces from domestic sources.

Export earnings from crude oil and petroleum products are projected to be significant. In 1994, the value of crude oil and oil product exports was $11.6 billion and imports was $6.7 billion, resulting in a surplus of $4.9 billion. In 2010, forecast net oil exports would imply that the net trade surplus from crude oil and products could surpass $7.5 billion before declining to about $6 billion in 2020.

Natural Gas Supply and Trade Projections

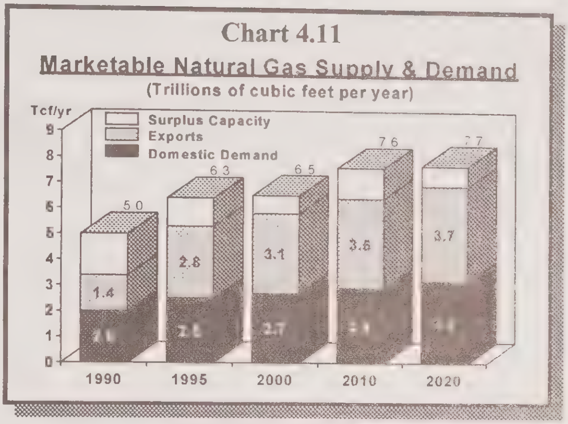


Chart 4.11
Marketable Natural Gas Supply & Demand
(Trillions of cubic feet per year)

Chart 4.11 shows marketable natural gas production, exports and total supply capability. Natural gas production grew significantly in the first half of the 1990s and is expected to continue to increase over the forecast period. Most of the growth in the first half of the 1990s occurred as a result of strong growth in exports. Natural gas production was 5.3 Tcf in 1995 and is projected to reach 6.9 Tcf in 2020. The growth in production over the projection period is expected to occur as a result of increased exports to the U.S., electricity conversion requirements and modest end-use demand growth.

Domestic demand is projected to increase from 2.5 Tcf in 1995 to 2.8 Tcf in 2000 and 3.2 Tcf in 2020, or about 1.0 percent per year. This increase includes requirements for electricity conversion of 0.5 Tcf by 2020 or three times the current level.

Natural gas exports, in 1995, reached 2.8 Tcf, reflecting rapid increases over the past 9 years. Canadian natural gas exports now account for about 50 percent of Canadian natural gas production and 12 percent of U.S. demand. Some regions in the United States now depend heavily on Canadian natural gas supply. Natural gas trade in North America will continue expanding and Canada is expected to play a major role in meeting U.S. requirements. Natural gas exports are projected to increase from the 1995 level of 2.8 Tcf to 3.1 Tcf in 2000 and 3.7 Tcf in 2020. These levels are reasonably consistent with most expert views although somewhat less optimistic than the U.S. DOE projection of Canadian exports at about 4.1 Tcf by 2015. NRCan's estimate implies that natural gas exports would continue to account for about 50 percent of Canadian production and fall within the range of 12-14 percent of the U.S. needs by 2015.

The increase in natural gas exports should contribute more significantly to Canada's energy trade surplus. Earnings from natural gas exports were $6.8 billion ($1995) in 1994. Given the increase in natural gas exports and prices, revenues could reach $9.5 billion ($1995) by 2020.

4.2 Coal Supply and Demand

This section discusses the supply and demand of coal for Canada. As shown in Chart 4.12, domestic coal supply is not resource constrained. The known resource base is large enough to last more than a century at the current rate of use.

Chart 4.12

Canada's Coal Resource Base (Million tonnes)

General Rank Class	Measured[1] Reserves	Years of Production
Bituminous	4,635	122
Sub-bituminous	2,230	86
Lignite	13,925	1,266

[1] Source: Statistical review of coal in Canada 1995. Natural Resources Canada.

Chart 4.13 summarizes the supply and demand forecast for Canadian coal. In 1995, the total coal supply amounted to 87 million tonnes (Mt), about 75 Mt was produced domestically and the rest imported from the United States and Colombia. Canadian coal production is concentrated in Alberta, British Columbia, Saskatchewan and Nova Scotia. Together, these provinces produce more than 99 percent of total Canadian coal production. By quality, domestic production of coal in 1995 amounted to 38.6 Mt of bituminous (⅔ from B.C., ⅓ from Alberta), 25.6 Mt of sub-bituminous (Alberta), and 10.7 Mt of lignite (Saskatchewan).

Chart 4.13

Summary: Coal Supply and Demand

	1990	1995	2000	2010	2020
	(Mt)				
Coal Production[1]	66	77	75	79	88
Imports	14	10	8	13	23
Total Supply	80	87	83	92	111
Domestic Demand	49	53	48	55	74
Exports	31	34	35	37	37
Total Demand	80	87	83	92	111
Net Exports	17	24	27	24	14

[1] Includes stock change.

The Outlook forecasts a relatively small increase in Canadian coal production between 1995 and 2010.

However, between 2010 and 2020 production should increase, from 79 Mt to 88 Mt, mainly in response to increased demand for thermal coal in Ontario. Coal imports, about 10 Mt currently, will increase to 13 Mt by 2010 and to 23 Mt by 2020.

Alberta, the largest Canadian coal producer at 37 Mt in 1995, will increase output to reach 46 Mt by 2020. British Columbia's coal production, chiefly metallurgical and almost entirely exported, is not projected to increase significantly from the 24 Mt mined in 1995. Saskatchewan is expected to increase its production from 11 Mt in 1995 to 13 Mt by 2020.

Demand for coal is derived from our projection of requirements by end-use sectors, largely metallurgical coal, and thermal requirements for electricity generation. In 1995, Canadian coal consumption was 53 Mt, 8 percent more than recorded in 1990. More than 88 percent of Canadian coal consumption is for electricity generation, about 8 percent is used in steel production, and the remainder (4 percent) is used by other industries, mainly cement. Canada exported 34 Mt of coal in 1995 (45 percent of total production) to 20 countries, of which 84 percent was metallurgical coal. Japan with 18 Mt in 1995 has been the largest importer of Canadian coal.

Total domestic demand for coal is expected to increase from 53 Mt in 1995 to about 74 Mt by 2020. Electricity generation, mainly in Ontario, accounts for the lion's share of this increase reflecting the anticipated retirement of nuclear plants and an increased demand for electricity.

The Outlook assumes that, unless a new market is found for Canadian metallurgical coal, Canadian exports will stay flat at the 1995 level. The export of thermal coal is expected to increase marginally to reflect higher demand in Asia - Pacific nations. As a result, Canadian coal exports are projected to increase by 10 percent from 34 Mt in 1995 to 37 Mt by 2020.

Alberta, the largest consuming province, used 26 Mt of coal to generate electricity in 1995. Due to the high capital costs associated with large coal fuelled power plants, some of the increase in electricity generation will be met by natural gas, consequently, limiting any significant increase in demand for coal in Alberta.

Saskatchewan, used 10 Mt of coal in 1995, 29 percent more than in 1990. Most of the coal consumed was for the generation of electricity. While increases in electricity generation prior to 2015 are satisfied by natural gas, a combination of coal and natural gas is assumed after 2015. Coal consumption should rise to 12 Mt by 2020.

Ontario, the second largest coal consumer, uses coal for electricity generation, steel production and general industrial purposes. Ontario's coal consumption declined gradually from 20 Mt in 1988 to 12 Mt in 1995 largely reflecting the completion of the Darlington nuclear station and the mothballing of the Lambton thermal plant. The re-opening of the Bruce B nuclear facility will lead to a further reduction in coal consumption to 7 Mt by 2000. After 2010, due to the retirement of some of the older nuclear plants, demand for coal should significantly increase to 28 Mt by 2020.

New Brunswick burns coal mainly for electricity generation. In 1995, the province consumed 1.3 Mt of coal, 1 Mt of which was imported from Colombia and the U.S. The Outlook does not call for any increase in coal consumption before 2017. Between 2017 and 2020 the demand for coal in New Brunswick will increase from 1.3 Mt to 3.3 Mt due to the opening of one electricity generation plant.

Nova Scotia consumed 2.6 Mt of coal in 1995, nearly all of which was to generate electricity. The share of coal in electricity generation will remain stable during the forecast period and as a result, demand for coal in Nova Scotia will increase from 2.6 Mt in 1995 to 3.3 by 2020. It should be noted, however, that if natural gas from the Sable Island Project penetrates the domestic market, coal and oil consumption in both Nova Scotia and New Brunswick could be substantially reduced. Coal, however, will still remain the fuel source for electricity generation used in base load power plants.

Chapter 5

Electricity Generation

This chapter examines the electricity market structure and the level and mix of generating capacity needed to satisfy the projected electricity demand presented in Chapter 3, and the anticipated electricity exports (discussed below). This total demand, together with information on utilities' long term generation expansion programs, provide an electricity supply scenario for each province and territory. The required new capacity will come not only from utilities but also from industry self-generation and independent power production (IPP).

5.1 Market Structure and Framework Assumptions

Canada's electric power industry is currently made up of provincial Crown corporations, investor-owned utilities, municipal distribution utilities and industrial establishments. In most provinces, the industry is highly integrated with generation, transmission and distribution provided by a few dominant utilities. Most of these utilities are Crown corporations owned by the province. Some, in Newfoundland, Prince Edward Island, Nova Scotia and Alberta, are privately owned. In addition to these major electric utilities, there are many industrial and independent establishments which generate electricity for their own use or for sale to major electric utilities.

The electricity industry is currently entering a period of fundamental change. Internationally there is a trend toward a more competitive, deregulated electricity market. These changes were pioneered in Europe, especially Britain and Norway, and a similar process is underway in North America. The United States Federal Energy Regulatory Commission (FERC) is mandating open access for wholesale transactions and various states are considering how to implement retail access.

In Canada many provinces are considering deregulation and/or privatisation of electric power utilities. The process has already started in some provinces. Alberta has gone further than any other province (and probably further than any jurisdiction in North America) in establishing an open access, competitive electricity market. In Ontario, the recently released "Macdonald Report"[26] outlines a framework for a comprehensive restructuring of the province's electricity system. B.C. Hydro has outlined a far reaching policy for access to transmission lines which the British Columbia Utilities Commission (BCUC) approved in July 1996. Hydro Quebec, through the "reciprocity principle", will allow distributors outside Quebec to use its transmission system to deliver energy to their clients elsewhere in Canada or in the United States.

Snelson International Energy[27] in its study conducted for NRCan concluded that most Canadian provinces will make significant moves toward a competitive and privatized electricity market over the next decade. This conclusion was reached after an extensive round of consultations with provincial utilities and energy ministries. The conclusion also reflects a consensus of expert views regarding the future evolution of electricity markets. The Outlook incorporates many of the views of the Snelson Study as they pertain to the evolution of the electricity generation mix over the next several decades.

- A more competitive environment, which permits "more efficient plant utilization, higher load factors and less capacity". Thus, with the exception of some small natural gas and renewable energy generating facilities, no new capacity will be required before the middle of the next decade. Existing thermal units are assumed to be life-extended to last 50 years.

- When new or replacement capacity is required, it will not come from large hydro or nuclear power. The existing nuclear facilities will not be replaced although, where possible, they will be retubed to extend their period of usefulness. The only large scale hydro project likely to come on stream is a portion of the Grande Baleine project in Quebec. All other new hydro projects will be less than 500 MW in size.

- The preferred new generation options will be natural gas (combined cycle and cogeneration) and refurbishments of existing thermal facilities. In a competitive market, natural gas fired generation offers many attractive features including relatively low capital costs, high level of efficiency, low emissions, short planning and construction lead-time, sizing to market requirements and proven reliability.

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26 The Report of the Advisory Committee on Competition in Ontario's Electricty System to the Ontario Minister of Environment and Energy, A Framework for Competition, May 1996

27 Snelson International Energy, Competition In Electricity Supply: Implications For The NRCan Energy Outlook. Prepared for Natural Resources Canada, June 1996.

- Trading between jurisdictions may become more volatile but will not lead to large sustained changes in volume. It is cheaper to transport fuel and build generation close to the market than to transport electricity. In the long run, any price differential between neighbouring provinces will be significantly reduced.

- The electricity from renewable energy, (i.e., biomass, waste, wind, geothermal, small hydro), is assumed to increase from 5.4 Terawatt hour (TW.h) in 1995 to 20.2 TW.h (3 percent of total) by 2020. This rapid increase in generation from renewable sources (mainly biomass and waste) will be achieved mainly as a result of strategies such as that announced by the federal government.

The federal government recently outlined its strategy for promoting renewable energy technologies[28]. NRCan will implement this strategy through a partnership approach which will ensure a better focus for federal initiatives, and enable participants to use their resources more efficiently. The Government's strategy emphasizes cost-shared, voluntary and economically sound initiatives.

Activities and initiatives under NRCan's Renewable Energy strategy can be categorized under three headings:

- enhancing investment conditions, by ensuring that renewable energy investments receive appropriate tax treatment and improved access to financing[29];

- technology initiatives to ensure better knowledge and technology availability through the development and use of renewable energy sources; and,

- market development initiatives to stimulate interest in renewable energy among end-users and suppliers through initiatives such as market assessment, information and education, technical training and green power purchasing.

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28 Renewable Energy Strategy, Creating a New Momentum. Natural Resources Canada, October 1996.

29 In the March 1996 federal budget, the rules governing the use of Class 43.1 capital cost allowance were relaxed and the intangible components of renewable energy investments were made eligible for flow-through shares. These measures were designed to expand the access to financing of renewable energy projects.

5.2 Electricity Demand

Domestic electricity demand is projected to grow at an average annual rate of 1.0 percent for the next 25 years (Chart 5.1), a much lower rate than the 2.6 percent witnessed during the last 15 years (1980-1995). As a result, significant amounts of excess generating capacity exist in all regions of Canada, as power plants were built in the 1970s and 1980s to meet projected high loads that have not yet materialized. This leads to a situation where no additional generating capacity is required to meet growing electricity demand until the year 2010 in all regions of Canada.

Chart 5.1
Provincial Electricity Demand (GW.h)

	1995	2020	AAGR* (%) 1995-2020
Newfoundland	11 181	14 027	0.9
Nova Scotia	10 032	11 985	0.7
P.E.I.	831	890	0.3
New Brunswick	14 300	17 831	0.9
Quebec	175 201	216 810	0.9
Ontario	138 898	189 761	1.3
Manitoba	19 551	24 522	0.9
Saskatchewan	16 212	21 097	1.1
Alberta	51 337	61 041	0.7
British Columbia	60 430	86 067	1.4
Yukon	390	701	2.4
Northwest Territories	613	876	1.4
Canada	***498 976***	***645 608***	***1.0***

* AAGR : Annual Average Growth Rate.

Chart 5.2 provides the assumptions regarding electricity exports. The projected exports are based on the continuation of existing firm and interruptible contracts and agreements only. Total electricity exports to the U.S., 41 TW.h in 1995, are projected to increase to 46 TW.h by 2000. They will then begin to decrease to 22 TW.h by 2020, as excess generating capacity dwindles due to increasing domestic demand, decommissioning of old power plants, and the better sizing of new capacity to meet higher load.

Chart 5.2
Firm and Interruptible Electricity Exports (GW.h)

	1995	**2000**	**2010**	**2020**
New Brunswick	3 345	2 399	2 399	2 399
Québec	17 049	19 997	10 587	10 341
Ontario	9 195	8 545	3 595	2 955
Manitoba	9 139	6 132	4 206	4 446
Saskatchewan	106	100	100	100
Alberta (via BC)	434	1 610	440	140
British Columbia	1 328	7 385	8 205	1 525
Canada	***40 596***	***46 168***	***29 532***	***21 906***

5.3 Electricity Supply Scenario

For each province and territory an electricity supply scenario has been built for the study period. Existing utilities' generating capabilities are prepared from data collected by the National Energy Board; information on new power plants are obtained from utilities or from the consultation undertaken for the Snelson report and other published sources. The timing and sequence of capacity additions are designed to meet the projected demand, exports, and decommissioning of older power plants. Given the evolving competition in electricity markets, we do not make any assumptions concerning whether the new capacity is built and operated by utilities or independent power producers.

Newfoundland and Labrador

On the Island, a 143 MW heavy oil-fired power plant is anticipated to be built by 2000 to supply power to the planned Voisey Bay Nickel Smelter. To meet the projected load growth and to replace decommissioned units at the Hollyrood site, two 150 MW oil-fired combined cycle units will be built by the end of the study period. In Labrador, additional internal combustion (diesel) turbines are projected by 2000 to meet new load resulting from new and expanded mining activities.

Nova Scotia

Due to the low projected growth in electricity demand, new base load power plants will only be needed during the second half of the 2010 decade. A 170 MW oil-fired combined cycle power plant and two 165 MW Circulating Fluidized Bed coal combustion units are anticipated to be built after 2015 to replace older units being retired. All of the offshore natural gas (Sable Island) is assumed to be exported to the U.S. and not available for electricity generation.

Prince Edward Island

Although Maritime Electric has sufficient capacity on the island to meet P.E.I electricity demand, it has been purchasing over 90 percent of its electrical needs from New Brunswick Power via a 200 MW submarine cable to offset its high cost oil-fired generation. With a very low projected load increase, no new capacity is expected to be built on the Island. Thus, it is anticipated that P.E.I. will continue to purchase over 90 percent of its requirements from the mainland.

New Brunswick

With a projected low load growth, excess generating capacity is likely to last until the late 2010s. New Brunswick Power is expected to build two 443 MW coal-fired power plants at the Belledune site by 2016-2017 to replace old oil-fired units being decommissioned. By 2008 the nuclear generating station at Lepreau is assumed to be retubed to last 40 years in total. As is the case in Nova Scotia, natural gas is assumed not to be available for electricity generation.

Quebec

The 828 MW Sainte Marguerite hydroelectric power plant will be in service, as planned, in 2001. Thereafter, the Eastmain 1, Mercier, Kipawa, Haut Saint Maurice and Ashuapmushan hydroelectric stations (2 015 MW) are anticipated to be developed when demand exceeds generating capabilities during the 2010 decade. The Grande Baleine Complex (3 173 MW)is assumed to be built in successive stages, with the GB 1 site projected by 2019. By 2011 the Gentilly 2 nuclear generating station is assumed to be retubed to last 40 years in total.

Ontario

The existing oil-fired units are assumed to be demothballed and switched to burn natural gas. The provincial utility is expected to pursue a long term supply strategy consisting of building natural gas-fired combined cycle units, coal-fired power plants using clean coal technologies, and redeveloping several existing hydroelectric stations (Niagara, Mattagami, Patten Post, Little Jackfish). During the last decade of the forecast, 3 650 MW of new gas-fired and 3 300 MW of coal-fired base load capacity will be built.

In 1995, unit 2 at the Bruce Nuclear Complex was mothballed. All remaining nuclear capacity (Pickering, Bruce, Darlington) is assumed to be retubed to last 40 years. As noted above, decommissioned units will not be replaced with new nuclear capacity. By 2020, the 9 028 MW remaining capacity (Bruce B, Pickering B, Darlington) will represent only 23 percent of installed capacity in the province, compared to 45 percent in 1995.

Manitoba

Current generating capacity is projected to be able to meet the low load growth in the province until 2011. The Wukswatim and the Notigi hydroelectric stations (405 MW), as well as two gas-fired combined cycle units (400 MW) are anticipated to be built during the 2010 decade.

Saskatchewan

New base load power plants will not be required until 2009. Saskatchewan Power is expected to build 600 MW of natural gas-fired combined cycle units and 544 MW of coal-fired power plants using clean coal technologies such as Integrated Coal Gasification Combined Cycle (IGCC) during the 2010s.

Alberta

With a low load growth and an expected strong increase in small natural gas plants (see Chart 5.5), excess generating capacity in the Alberta Interconnected System (AIS) is likely to last until 2011. AIS is expected to pursue a long term supply strategy consisting of building natural gas-fired combined cycle units and coal-fired power plants to replace older units being retired as well as to meet higher electricity demand. During the 2010 decade, 1 200 MW of new gas-fired and 740 MW of coal-fired base load capacity are anticipated to be built.

Reflecting developments in the oilsands and petrochemical industries, several cogeneration facilities - at Syncrude, Cold Lake and Joffre - will be developed by 1999-2003.

British Columbia

The province is expected to fully utilize its Columbia River Downstream Benefits (950 MW) starting in 1998 to meet its increasing energy demand. The redevelopment of Stave Falls and Seven Mile hydroelectric stations, the repowering of the Burrard gas-fired power plant, and a substantial increase in small generating facilities (see Chart 5.5), will postpone the need for new capacity until the second half of the 2010s. Waneta, Brillant, Keenleyside and Murphy Creek hydro generating stations (1 044 MW) are anticipated to be developed during the 2015-2020 period.

Yukon and Northwest Territories

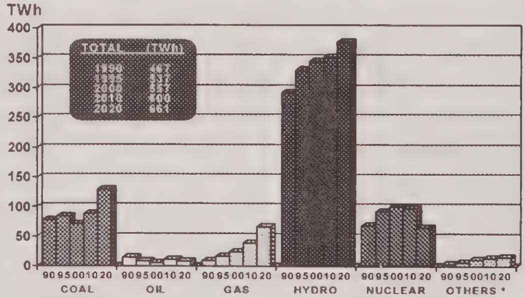
Unlike the provinces, the Yukon and Northwest Territories do not have an interconnected network; the total electricity demand is a combination of isolated loads. Actual dependable capacity is anticipated to be sufficient to meet the projected electricity demand in the Northwest Territories during the study period. In the Yukon, small internal combustion (diesel) units and small hydro projects are expected to be built when load requirements exceed dependable generating capacity during the 2010s.

National Trends

In 1995 total electricity generation for domestic demand and exports to the U.S. was 537.2 TW.h, with 63 percent from renewable sources such as hydro and others (biomass, waste, wind, etc.), 17 percent from nuclear and 20 percent from fossil fuels (see Chart 5.3). In 2000 it is projected to

Chart 5.3

Electricity Generation by Fuel: Canada



* Others are fuels such as biomass, wind, etc., not included in the main fuel types.

increase by 3.7 percent to 557.3 TW.h; however, the relative share from fossil fuels will decrease to 18 percent with the biggest drop coming from coal, the most carbon intensive fuel. By 2020, total electricity supply will be 23 percent higher than in 1995; the share from fossil fuels will jump to 31 percent of the total.

As a preferred fuel in Central and Western Canada for new power plants, natural gas is anticipated to be the fuel with the biggest growth rate, progressing from a share of 3 percent in 1995 to 10 percent in 2020. In other words, gas-fired generation will be four times higher in 2020 than it was in 1995, and will be on the same level as nuclear generation. Electricity from coal is projected to decrease by 2000, reflecting increased generation from nuclear power plants in Ontario and New Brunswick and from natural gas in Alberta. Between 2000 and 2010 it will experience a gradual comeback as excess capacity dwindles. During the 2010 decade, coal-fired generation will increase as a result of new capacity being built in the Maritimes, Ontario, and the Prairies. Oil-fired generation is expected to follow the same path as coal generation between 1995 and 2010. By 2020 it will mainly be used in the Atlantic region and in the remote communities.

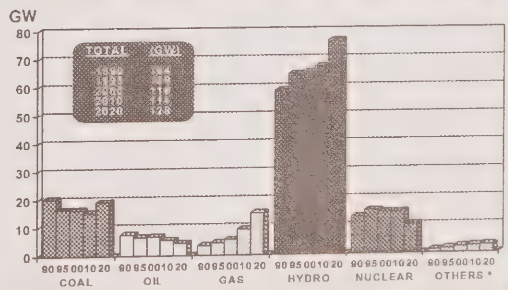
All nuclear power plants in Ontario and New Brunswick are expected to be back to normal operation by 1997. Production is anticipated to remain constant until 2010 then starts to decline gradually as 4.4 GW of old nuclear power plants built during the 1970s in Ontario are decommissioned. By 2020, generation from nuclear energy will represent only 10 percent of the total. This is the only fuel to see a decrease both in importance and in energy production, a consequence of the replacement of old nuclear capacity in Ontario with new natural gas and coal capacity during the 2010s.

Hydroelectricity is and will remain the dominant source of electricity. Over the study period, its generation is still growing, although its relative share is expected to diminish slightly from 62 percent in 1995 to 57 percent by 2020.

Electricity from renewable energy, such as biomass, waste, wind, geothermal, small hydro, is anticipated to witness a very high growth, jumping from a relative share of 1 percent in 1995 to 3 percent by 2020. The bulk of the increase is in generation from biomass and waste fuels. However, electricity production will still be a modest 20 TW.h by the end of the study period.

Chart 5.4

Generating Capacity by Fuel: Canada



* Others are fuels such as biomass, wind, etc., not included in the main fuel types.

The Outlook shows that Canada will continue to rely on conventional sources of supply such as hydro, coal, natural gas and nuclear to meet its growing electricity demand. Natural gas is projected to become one of the preferred fuels for new power plants post 2010.

Chart 5.5
Projected Small Power Generating Capacity (MW)

		1995	2000	2010	2020	Capacity Factor %
Atlantic	Small Hydro	5	50	50	50	66
	Oil	2	2	25	47	79
	Others *	9	91	267	298	83
	Total	16	143	342	395	-
Quebec	Small Hydro	116	149	189	189	81
	Natural Gas	30	55	65	77	85
	Others *	37	188	189	190	66
	Total	183	392	443	456	-
Ontario	Small Hydro	150	150	150	150	50
	Natural Gas	394	975	1083	1215	82
	Others *	351	513	538	567	76
	Total	895	1638	1771	1932	-
Manitoba	Natural Gas	0	0	1	3	80
	Others *	0	0	5	11	80
	Total	0	0	6	14	-
Saskatchewan	Natural Gas	40	85	132	146	80
	Others *	0	28	48	53	67
	Total	40	113	180	199	-
Alberta	Small Hydro	49	52	52	52	47
	Natural Gas	0	200	674	764	80
	Others *	63	93	122	158	50
	Total	112	345	848	974	-
B.C.	Small Hydro	16	87	132	132	90
	Natural Gas	105	235	1082	1119	87
	Others *	79	225	336	470	83
	Total	200	547	1550	1721	-
Canada	Small Hydro	336	488	573	573	-
	Natural Gas	569	1550	3037	3324	-
	Oil	2	2	25	47	-
	Others *	539	1138	1505	1747	-
	Total	1446	3178	5140	5691	-

* Others are fuels such as biomass, waste, wind, etc., not included in the main fuel types.

Chapter 6

Primary Energy Demand

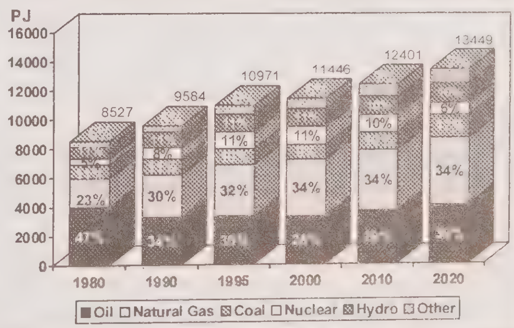
Primary energy demand represents the total requirement for all uses of energy in Canada, including energy used by the final consumer, intermediate uses of energy in transforming one energy form to another (i.e., coal to electricity), and fuel used by suppliers in providing energy to the market (i.e., energy requirements by oil and natural gas producers).

6.1 Total Primary Demand by Fuel

Over the period 1980-1995, total primary demand for energy increased by 29 percent averaging 1.7 percent per year. Total demand is projected to grow by 23 percent over the 25-year period 1995-2020, averaging 0.8 percent per year, which is half the average annual rate observed over 1980-1995. Historical data and projections are shown in Chart 6.1. Over the period 1995-2020, the growth in demand for natural gas (including liquified petroleum gases) is 30 percent, while for refined petroleum products (RPPs) and coal, it is 22 and 44 percent respectively. Hydro electricity generation increases by 14 percent while nuclear electricity declines by 29 percent over the forecast period.

Chart 6.1

Primary Energy Demand by Fuel: Canada

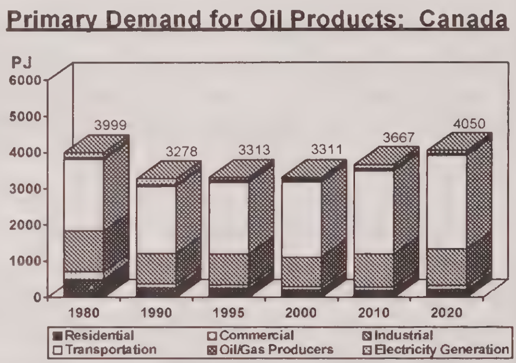


6.2 Demand for Refined Petroleum Products

Primary demand for RPPs is composed of residential, commercial, industrial, transportation, electricity generation and oil and gas producing sectors. While total primary demand increased by 29 percent over 1980-1995, demand for RPPs declined by 16 percent. RPPs demand declined by 1.2 percent per year during that period, which was characterized by energy efficiency measures and inter-fuel substitution. Following a 15-year period of continuous decline, demand for RPPs is projected to remain stable until the year 2000 before increasing by 1 percent per year over the period 2000-2020.

Chart 6.2 shows RPPs primary demand by sectors. Sectorally, demand for oil products by the residential sector continues to moderately decline in absolute level and as a percentage of total demand over the forecast period. Commercial and industrial sectors' demand are projected to decline over the first 5 years of the forecast, before increasing by about 20 percent over 2000-2020, maintaining their relative shares in total RPPs demand. On the other hand, transportation demand rises by 31 percent, averaging an annual rate of growth of 1.1 percent, which results in a 4 percentage point increase in RPPs relative share to 64 percent by 2020. Oil demand by the electricity generation and fossil fuel producing sectors will remain relatively small at 1 to 2 percent of the total oil demand.

Chart 6.2



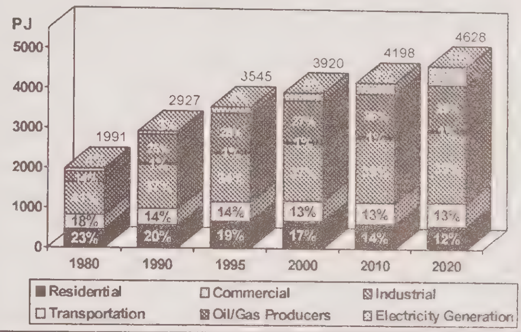
6.3 Demand for Natural Gas

Unlike oil, the demand for natural gas has increased by 77 percent over 1980-1995, averaging an annual rate of 3.9 percent. Natural gas was the major beneficiary of oil substitution initiatives such as the Canadian Oil Substitution Program. Over the period 1995-2000, demand for natural gas is projected to grow by 11 percent in total, and for the period 2000-2020, demand increases by 18 percent, averaging an annual rate of 0.8 percent. The relative share of natural gas in total primary demand increases from 23 percent in 1980 to 32 percent in 1995, and is expected to rise to 34 percent by 2020. Historical data and projections on natural gas demand are shown in Chart 6.3.

Sectorally, over the period 1995-2020, natural gas use in the residential sector is declining in absolute levels mainly because of substantial efficiency improvements in furnaces and water heaters. Commercial sector demand grows by 22 percent over the entire forecast period while maintaining a relative share of approximately 13 percent through 2020. The major sources of growth in natural gas use will be from industrial and electricity generation sectors. The demand for the industrial sector is projected to grow by 46 percent over the forecast period. Natural gas demand for electricity generation is expected to triple, averaging a 4.7 percent annual increase. The high rate of growth in the power generation sector is due to the partial displacement of coal (in the short term) and nuclear (in the longer term) by natural gas. The growth in the industrial sector is attributed to the expectations of strong output performance. Demand by the oil/gas producing sector is expected to grow a little, with its relative share declining from 28 percent in 1995 to 25 percent by 2020.

Chart 6.3

Primary Demand for Natural Gas: Canada



6.4 Demand For Other Fuels

Demand for coal increased on average by 1.2 percent per year over the period 1980-1995. However, after declining during the period 1995-2000, demand for coal increases at an average rate of 2.4 percent per year, as coal progressively compensates for the decline in nuclear-generated electricity. As a consequence, the relative share of coal in total fuel demand is projected to increase from about 10 percent in 1995 to 12 percent by 2020. Nuclear electricity generation, which increased on average by 7 percent per year over 1980-1995, is projected to decline by 1.3 percent per year over 1995-2020, as some nuclear plants are retired.

Demand for renewable forms of energy, which grew on average by 3.4 percent per year over the period 1980-1995, is projected to rise at a much slower rate of 1.7 percent over the 25-year forecast. As a result, the relative share of renewable energy, which was about 5 percent in 1980, is projected to increase moderately from 6 percent in 1995 to 7 percent in 2020.

Chapter 7

Greenhouse Gas Emissions

This chapter offers a reference projection for Canada's greenhouse gas (GHG) emissions over the next twenty-five years. The projection covers emissions both from energy use, about 90 percent of the total, and from non-energy sources. Estimates for the latter were developed by Environment Canada using the same assumptions used in the Outlook.

The remainder of the chapter is organized as follows:

- section 7.1 provides the projections for the four major sources of GHG emissions - direct consumption of fossil fuels by end-use sectors, electricity generation, fossil fuel production and non-energy sources;
- section 7.2 examines the short and long-term trends for total GHG emissions from various perspectives;
- section 7.3 explores the sensitivity of the results to changes in major assumptions; and,
- the final section summarizes the major conclusions of the projection and suggests its implications for policy.

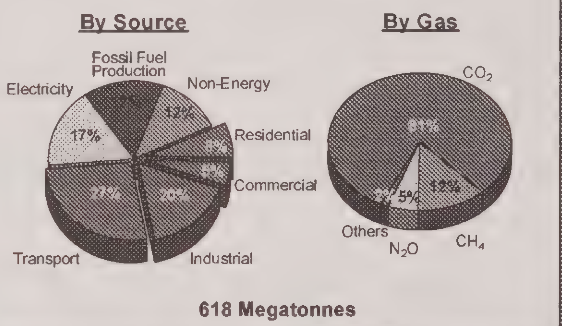
7.1 Sources of GHG Emissions

In 1995, Canada's total anthropogenic emissions, on a CO_2 equivalent basis, were 618 megatonnes (Mt). As shown in Chart 7.1, CO_2 accounted for over 80 percent of this total with methane (CH_4) as the next largest contributor (12%).

In terms of sources, it is clear that fossil fuel energy is responsible for, by far, the lion's share of emissions (88 percent). Direct fossil fuel consumption by end-use sectors accounts for 60 percent of total emissions with transportation, followed by the industrial sector[30] generating the largest shares. Electricity generation, using coal, natural gas and fuel oil, contributes 17 percent of emissions while fossil fuel production accounts for about 12 percent. Non-energy sources include CO_2 from cement and lime production and soil erosion; methane (CH_4) from landfills and domestic animals; nitrous oxide (N_20) from industrial processes, adipic acid production and fertilizer; and various fluorine compounds used in industrial processes and as propellants. Collectively, non-energy sources are responsible for about 12 percent of total emissions.

Chart 7.1

1995 GHG Emissions



The remainder of this section presents the trends in emissions from these four principal sources. Depending on the source being examined, the presentation covers the underlying energy projection and the impact of initiatives developed as part of the National Action Program on Climate Change (NAPCC).

Emissions From Direct End-use of Energy

Emissions from the direct end-use of energy are those generated from the combustion of fossil fuels in the four end-use sub-sectors: residential; commercial; industrial; and, transportation. Carbon dioxide accounts for the overwhelming share of these emissions, with small volumes of N_2O, principally from road transportation.

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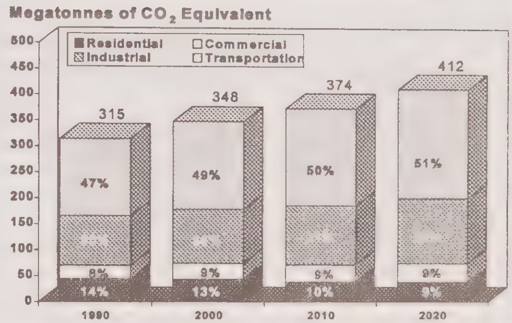
30 Emissions from non-combustion uses of fossil fuel energy: i.e., feedstocks, asphalt, lubes and greases, are included in the industrial sector. In 1995 these emissions were 20Mt, about 4 percent of the total.

The emissions trend in this sector is thus largely determined by the outlook for energy demand in the four end-use sub-sectors discussed in chapter 3. Overall, end-use energy demand is anticipated, relative to 1995 levels, to increase by 5 percent by 2000 and 27 percent by 2020. These represent roughly one-third of the growth rate in the economy.

Chart 7.2 shows the projections for GHG emissions by the end-use sectors. The emissions portrayed are those associated with the direct combustion of fossil fuels (principally refined petroleum products and natural gas). Emissions from the generation of electricity to satisfy end-use demand are discussed later.

Chart 7.2

GHG End-Use Emissions



End-use emissions increase from 315 Mt in 1990 to 348 Mt in 2000 and 412 Mt in 2020, an overall growth of just over 30 percent. The largest source is the transport sector, obviously linked to the levels of gasoline, diesel and other motive fuels. Emissions from the industrial sector grow despite significant declines in energy intensity. The commercial sector contributes a constant and the residential sector a declining share.

The projections in Chart 7.2 reflect the impact of the many initiatives targeted to the end-use sectors and the VCR commitments by the industrial sector. Chart 7.3 provides the estimates of the GHG reduction impact of these measures.

The emissions level for the end-use sector, in the absence of initiatives, grows from 315 Mt in 1990 to 360 Mt in 2000 and 475 Mt by 2020. The impact of initiatives directed at the residential, commercial and industrial sectors, including associated reductions in electricity requirements, reduce these levels by

Chart 7.3

End-Use Sector: Impact of Initiatives

	1990	2000	2010	2020
	Megatonnes of CO_2 Equivalent			
Pre-Initiatives Level	315	360	401	475
Impact of Initiatives from Residential, Commercial & Industrial Sectors *	-	10	22	54
Impact of Transportation Initiatives	-	2	5	9
Post-Initiatives Level *	315	348	374	412

* Includes impact of initiatives which reduce electricity use by these sectors

10 Mt in 2000 and 54 Mt in 2020. Transportation initiatives add a further 2 Mt in 2000 and 9 Mt in 2020. The overall impact of initiatives in this sector is to reduce emissions by about 3 percent in 2000 and 14 percent in 2020.

Emissions From Electricity Generation

Over 80 percent of Canada's electricity production is generated by non-emitting GHG sources: principally hydro and nuclear power. Of the GHG emitting sources, coal (14 percent) accounts for the largest component, followed by natural gas (3 percent) and fuel oil (1 percent).

Based on the analysis in chapter 5, Chart 7.4 provides the projections for emissions from electricity generation by fuel. The overall pattern is quite volatile, largely reflecting variations in coal usage. From 2000, however, coal-related emissions grow significantly as new and refurbished coal-fired capacity is brought on stream to meet the demand.

Chart 7.4

GHG From Electricity Generation by Fuel

	1990	1995	2000	2010	2020
	Megatonnes of CO_2 Equivalent				
Coal	78	88	75	89	118
Fuel Oil	12	5	4	8	6
Natural Gas	4	10	9	13	22
Total (net of initiatives)	94	103	88	110	146
Electricity Generation Initiatives	-	-	3	3	3

For similar reasons, emissions from natural gas in 2020 are more than three times higher than in 1995. By contrast, fuel oil, and therefore its emissions, decline as it becomes, except in certain provinces such as Newfoundland (or isolated communities), a marginal fuel used for peaking.

The projections in Chart 7.4 are net of planned emissions reductions from operations, of approximately 3 Mt by 2000 announced, in its VCR submission, by the Canadian Electricity Association (CEA)[31]. The CEA has suggested that, given the many uncertainties in the electricity market, this reduction should be applied to the longer-term future.

31 Voluntary Actions by the Electricity Industry in Support of the VCR Program on Climate Change - October 21, 1996. Progress Report by the Canadian Electricity Association.

Emissions From Fossil Fuel Production

GHG emissions in this sector are derived from two principal sources:

- from fossil fuel used in the exploration, development, production and transport of crude oil, natural gas and coal; and,

- from fugitive emissions from the production and transport of these raw materials (i.e. venting, pipeline leakage).

Trends in both sources are closely related to the volume of oil, natural gas and coal production discussed in chapter 4. They can also be modified by improved monitoring and the application of technology.

The CO_2 and methane emissions associated with fossil fuel production and transport are presented in Chart 7.5. As expected, the increase in oil and natural gas production volumes generates significant increases in emissions levels. CO_2 emissions, largely related to oil sands and natural gas production, grow from 50 megatonnes in 1990 to 72 Mt in 2000 and to 88 Mt in 2020. Consistent with increased gas production, methane emissions, which grew 25 percent between 1990 and 1995, increase further by 2000 before plateauing at about 45 megatonnes after 2010 (a 55 percent increase over 1990 levels).

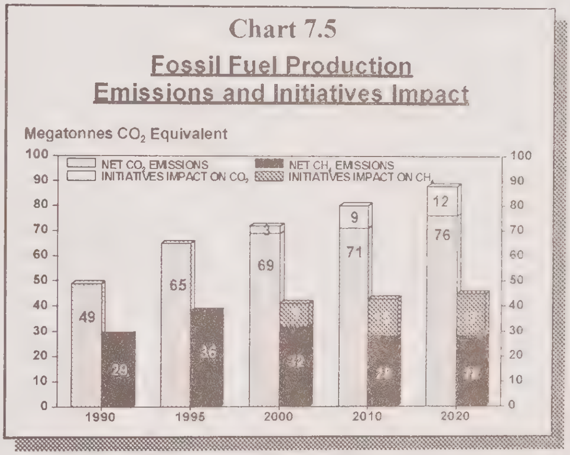


Chart 7.5
Fossil Fuel Production Emissions and Initiatives Impact

All of the above results are before consideration of the initiatives by the fossil fuel industry to reduce emissions. Based on an analysis of the VCR submissions of the industry and related evidence, a methodology has been developed which suggests that significant reductions, particularly for fugitive methane emissions, are likely[32]. For CO_2, these initiatives, principally

32 See Annex B.2 for a description of this methodology. VCR submissions examined include those of CAPP and its member companies, CEPA, TCPL, CGA, Syncrude and Suncor. The methodology has been reviewed with several organizations, most notably, with CAPP.

related to improved practice and new technologies employed by oil sands operations, are sufficient to hold emissions levels to about 75 Mt per year after 2010 despite considerable increases in production. For methane, the expected actions of producers and transporters are sufficient to reduce and then stabilize emissions from 2000 onward. This occurs despite an increase in gas production of some 30 percent over the same period.

Non-Energy Emissions

Non-energy sources of emissions (about 12 percent of the total emissions) include a variety of industrial, agricultural and waste-management processes in which greenhouse gas emissions are a direct by-product. These sources are summarized in Chart 7.6.

Chart 7.6

Non-Energy Emissions by Gas and Source, 1995

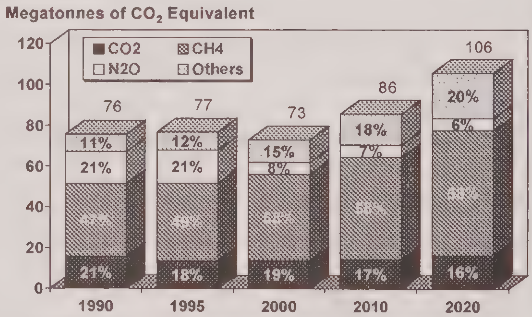
GHG	Emissions in 1995 Megatonnes of CO_2 Equivalent	Principal Sources
CO_2	13.8	cement and lime production, soil erosion
Methane	38.0	landfills, domestic animals, animals
Nitrous Oxide	16.0	anaesthetics, nitric and adipic acid production, fertilizers
Fluorine Compounds	9.0	CFC substitutes, aluminum and magnesium production
Total Non-Energy	76.8	

Methane emissions - from landfills and domestic animals - are the largest component of the non-energy sources. About two-thirds of non-energy nitrous oxide emissions are related to Dupont's adipic acid plant in Maitland, Ontario.

Chart 7.7 provides a projection of non-energy sources by emission type to 2020. Overall, non-energy emissions in 2000 are projected to be 4 percent lower than 1990 levels before increasing to 39 percent above 1990 levels by 2020. The main source of the decline is the major change in Dupont's adipic acid manufacturing process, to be phased-in between 1997 and 2000, which will reduce nitrous oxide emissions by approximately 10 Mt (CO_2 equivalent). Emissions from cement and lime production experience only modest growth

Chart 7.7

GHG: Non-Energy Emissions



Source: Environment Canada

owing to the greater use of fly-ash and further efficiencies in the processing of clinker. All other non-energy sources experience growth in emissions more or less in line with economic and/or population trends.

7.2 Results for Total Greenhouse Gas Emissions

This section gathers together the estimates in the previous section to provide several perspectives on the total GHG results. Given the policy focus on the stabilization commitment, the examination begins with the "gap" - the difference between emissions levels in 1990 and 2000.

As shown in Chart 7.8 the gap reported in the 1995 NAPCC document[33] was 73 Mt or 13 percent above 1990 levels. The current projection has the difference declining to 46 Mt or 8.2 percent above 1990 levels.

Chart 7.8

The GAP

Greenhouse Gas Emissions in 2000 versus 1990

	1990	2000	Difference	% Increase
	Megatonnes of CO_2 Equivalent			
1994 Projection in NAPCC	564	637	73	13.0
Current Projection	564	610	46	8.2

Chart 7.9 provides various perspectives on the gap - pre and post initiatives, by emissions type, fuel and sector. Several points are worth noting.

- In the NAPCC projection, the impact of initiatives known at that time, in 2000, was approximately 16 Mt. The current estimate, reflecting both increasing effort and the role of the VCR, is 38 Mt. Thus, progress in addressing the stabilization commitment has been on the order of 20 Mt.

- By emission, CO_2 is the largest contributor to the gap. Reflecting their small absolute contributions, CH_4 and N_20 account for smaller components of the increase.

33 Canada's National Action Program on Climate Change, pg. 7

- By fuel, the important role of natural gas, from production for export and additional domestic demand, is evident. Oil's contribution is small while those for coal and from non-energy sources are slightly negative. The latter reflects the significant reduction in N_2O emissions due to the change in the process for adipic acid production at the Dupont plant.

- By sector, both end-use and fossil fuel production contribute significantly to the gap. The latter is due to increased natural gas production for export noted above. Electricity generation and non-energy record negligible contributions (see discussion of coal and adipic acid above).

Chart 7.9

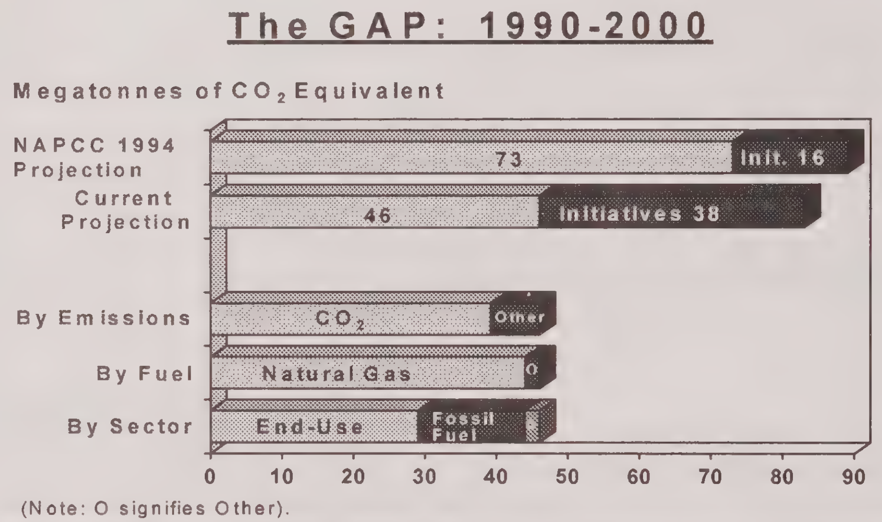


Chart 7.10 provides a view of the long-term trend in GHG emissions by type of emission. Following a slight decline in 2000, due largely to lower coal use in Ontario and the process change for adipic acid production, the growth in emissions is inexorably upward. By 2010, emissions are 105 Mt (19 percent) higher than in 1990. By 2020, they are 203 Mt (36 percent) higher. The primary sources of these increases are population and economic growth, coupled with low energy prices and a shift to fossil fuels, particularly natural gas, for electricity generation.

Methane emissions generally follow the overall upward trend. Nitrous oxide, however, declines as a result of the change in the adipic acid process before growing again due to increased emissions from catalytic convertors in automobiles and other vehicles. Other sources, principally CFC substitutes, also grow appreciably from a small base.

Chart 7.10

GHG Emissions

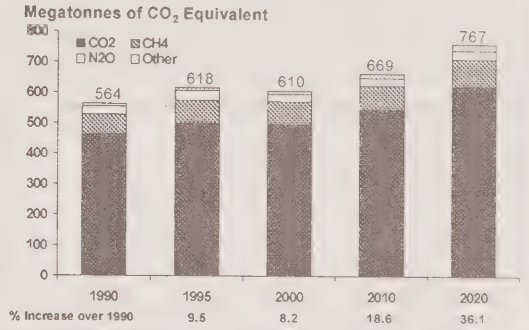
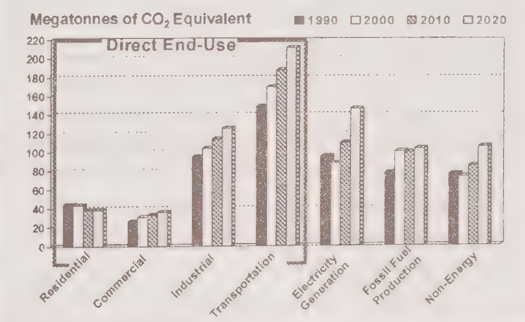


Chart 7.11 examines long-term emissions growth by sector. Transportation is the largest contributor to emissions both in absolute and growth terms. The increase in emissions from the industrial sector is also significant but the pace is somewhat slower. The commercial sector generates a modest increase and the residential sector an absolute decrease in emissions. These latter results are closely linked to the impact of energy-efficiency regulations on buildings, heating systems and other energy using equipment.

Chart 7.11

GHG by Sector



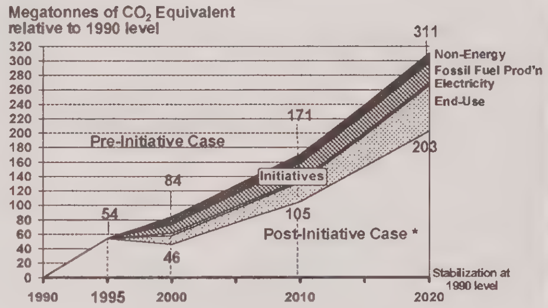
For electricity generation, emissions initially decrease but then climb significantly as natural gas and, to a lesser extent, coal become the preferred fuel sources. In the fossil fuel production sector, emissions grow rapidly from 1990 to 2000 but level off thereafter. This trend is related to the increasing effectiveness of initiatives to constrain CO_2 emissions and methane leakage by the oil and gas industry which take place against a backdrop of significantly increased production. Non-energy emissions initially decline, due largely to the new process for adipic acid production but then grow appreciably. The major driver of this growth is the increasing use of hydrofluorocarbon substitutes for CFCs.

Chart 7.12 portrays the impact of all initiatives on the growth in GHG emissions since 1990. In the absence of initiatives, emissions in 2000 would have been 38 Mt higher than the reference case or about 45 percent of the gap[34].

Over the longer term the initiatives are increasingly effective in constraining emissions growth (reflecting in part the working through of improved standards and practices as energy-using and energy-producing capital stock turns over). By 2020 for example, initiatives are responsible for 108 Mt of emissions reduction or about 35 percent of the growth of emissions since 1990 which would have otherwise taken place.

Chart 7.12

Impact of Initiatives



* Includes impact of initiatives which reduce electricity use by these sectors.

In terms of the various categories of initiatives, those related to end-use energy consumption are increasingly effective over time. Fossil fuel production initiatives make a large difference early in the period but, thereafter, the impact stabilizes as economic limits for methane capture are exhausted. The electricity generation initiatives remain constant at 3.3 Mt throughout, a possibly conservative assumption. In the non-energy category, the main element is the change in the process for adipic acid production.

Chart 7.13 portrays long-term emissions growth on a provincial basis. The information is organized so as to indicate, for each province, the percentage growth in emissions, in 2000, 2010 and 2020, relative to the 1990 level. Several points are worth noting:

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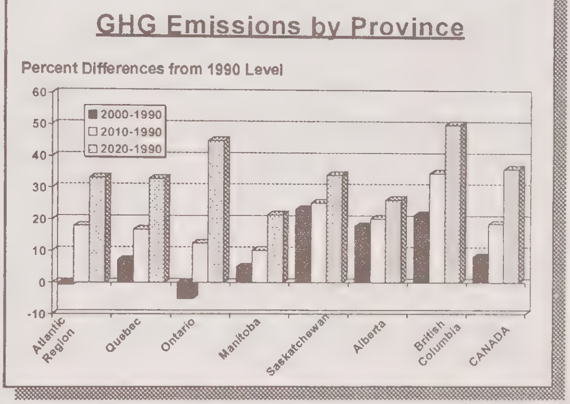
34 It is important to recognize that the initiatives impact portrayed above understates the effect of government and stakeholder action. The initiatives impact covers actions taken from 1995 only. The effect of earlier measures is already incorporated in the historical data and the reference projections. The underestimate is likely most pronounced for the end-use sector for which a number of programs and other measures have been in effect for several years.

- in the short-term, to 2000, emissions growth is greater than the national average in Saskatchewan, Alberta and British Columbia. These increases are associated with the resource boom in the west and, in the case of British Columbia, population increases;

- in the longer-term, however, growth in emissions is more evenly distributed across provinces, with Ontario and British Columbia recording above average increases. For the former, the chief reasons for the increase are the retirement of some of the nuclear plants and the greater use of natural gas and coal for electricity generation;

Chart 7.13



- the results for Alberta and, to a lesser extent Saskatchewan, suggest a deceleration in the growth of emissions after 2000. This is largely the result of the increasing effectiveness of the oil and gas industry initiatives to constrain emissions; and,

- while Quebec and the Atlantic region have minimal emissions growth to 2000, thereafter their results are more in line with national trends.

7.3 Sensitivity Analysis

Given the many assumptions required for its construction, it is almost inevitable that the projection will not accurately reflect the future. To provide a sense of the range of outcomes, Chart 7.14 examines the impact of a number of changes in assumptions.[35] Some of these

35 It is important to emphasize that these sensitivities are rough approximations. In each case, only one assumption is changed - everything else is held constant. Obviously cases such as a one percentage point change in economic growth or a doubling of energy intensity decline imply associated significant changes in Canada's economic structure.

changes - different economic growth prospects, higher world oil prices - reflect plausible alternate external developments. The others are highly stylized representations of possible policy directions.

Chart 7.14 is organized with reference to the differences in emissions, in various years, from 1990. Thus, for the reference projection, GHG emissions are projected to be 8 percent higher in 2000 and 36 percent higher in 2020.

Chart 7.14

Sensitivity Analysis: Projected Change in GHG Emissions Relative to 1990

	2000	2020
	% increase over 1990	
Reference Projection	8	36
Increase GDP by 1pp/year	11	58
Decrease GDP by 1pp/year	6	20
Increase oil price by US$ 5 per barrel	7	34
Decrease energy intensity by further 1 pp/year	5	13
Increase auto fuel standards by 3%/year (2000-10)		32
Retain nuclear capacity		32

Were Canada's annual economic growth to be one percentage point higher than in the reference case (i.e. 3.2 percent per year versus 2.2 percent), the gap in 2000 would be about 3 percentage points larger (i.e. from 8 percent to 11 percent). By 2020, the difference from the 1990 level would be almost 22 percentage points higher than in the current Outlook. By contrast, if economic growth were one percentage point lower throughout the projection period, emissions levels would also be appreciably lower. A $US 5 increase in the world oil price would, other things constant, modestly reduce the gap in both the short and the long term. This smaller decline is due to the fact that the resulting energy price increases would be concentrated in the transportation sector where fuels are already subject to considerable levels of taxation. Thus the relative price increases on gasoline and diesel would be muted.

Among the three "stylized" policy scenarios, it is clear that a generalized improvement in energy intensity of one percentage point (i.e. a decline of 2.2 percent per year instead of 1.2 percent) would result in a considerably more favourable emissions outlook. Emissions in 2020 would be only about 13 percent above the 1990 level compared to 36 percent above in the reference case. How such a general result could be achieved is not clear.

Of the two more focused scenarios, a 3 percent annual improvement in automobile fuel efficiency standards - about one half that achieved by the U.S. CAFE standards in the early 1980s - would have a modest impact. By 2020, when the full impact of this policy had worked its way through the vehicle stock, emissions would only be about 4 percentage points lower than in the reference case. Retention of Ontario's nuclear capacity, via replacement of, or life-extensions to existing facilities, would reduce emissions in 2020 by about 4 percentage points.

7.4 Implications for Policy

This section summarizes the major conclusions of the emissions projection using a scenario in which current policy is deliberately held constant. This constraint permits the examination of emissions trends in the absence of new policy initiatives.

Although it is not the purpose of this document to offer detailed policy recommendations, there are, however, a number of implications for policy which flow from the analysis.

- Canada is very unlikely to achieve the 2000 stabilization target in the absence of additional policy measures.

- The above conclusion appears to hold even if more optimistic assumptions from an emissions perspective - lower economic growth, higher oil prices - are employed. The greater risk is that the assumptions concerning economic growth and electricity prices are too pessimistic with the result that the gap will be larger.

- Although the policy response, to date, has had an impact, a considerably greater effort would seem to be required, within a very short timeframe, to achieve the stabilization objective. It is very unlikely that further large opportunities, such as the change in the process for producing adipic acid, exist.

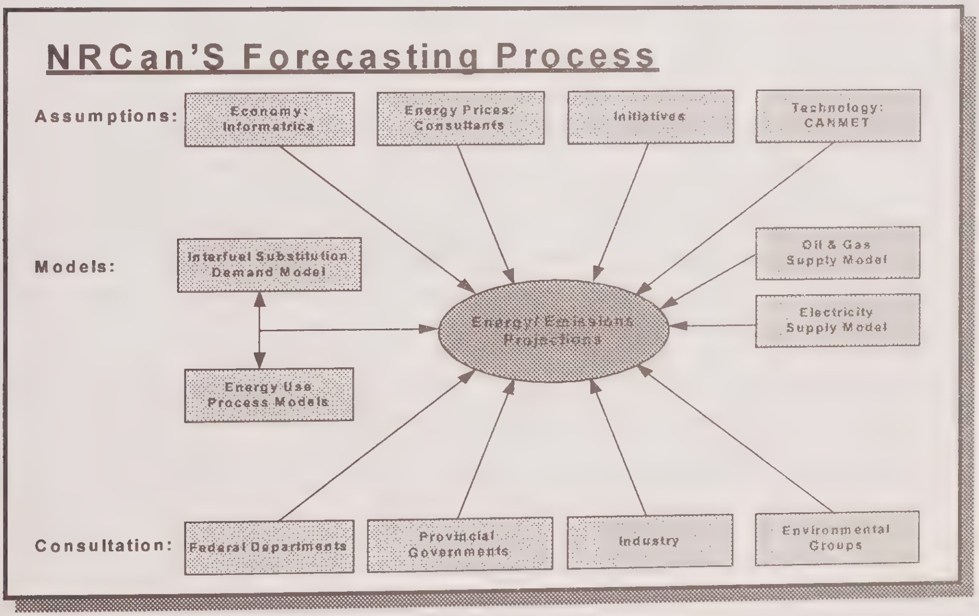
- Of particular note is the transportation sector, a major and growing source of emissions. There may be considerable potential in this sector, but it is very difficult to access by policy means. A somewhat similar conclusion applies to the industrial sector. Electricity generation may provide considerable opportunities but they are not achievable in the short term.

- The long term may provide greater scope for technological innovations to reduce GHG emissions. The Outlook, however, suggests that one should not be too sanguine about this prospect. The combined effects of population and economic growth, coupled with low energy prices, produce an inexorable growth in emissions. Without significant technological breakthroughs, even achievement of long-term stabilization will require major structural and life-style changes.

Annex A

Modelling Framework

The Energy Policy Branch (EPB) of Natural Resources Canada (NRCan) has developed and maintains an integrated modelling system that can produce consistent estimates of energy demand and supply and related emissions at the national and provincial levels, by fuel and by sector. The integrated framework consists of the Inter Fuel Substitution and Demand (IFSD) model, the Canadian Power Planning (CANPLAN) model for utility generation, and the Oil and Gas Supply (OGS) model. The modelling structure also includes several detailed end-use models for the residential, commercial and industrial sectors, maintained by the Energy Efficiency Branch (EEB). The Chart below provides an overview of NRCan's forecasting processes.



Because of its integrated nature, the models of the Energy Policy Branch (EPB) and the Energy Efficiency Branch (EEB) incorporate exogenously the impacts of several policy variables, such as improved appliance standards. They can reflect projected changes in prices and/or Gross Domestic Product (GDP), leading to changes in the level of environmental emissions.

Over the past few years, an emissions module has been added to the system to calculate projections of energy related emissions of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) by fuel, sector, and region. While the 1995 estimates of CO_2 emissions are closely aligned with that of Environment Canada, there remains some work to refine projection estimates for CH_4 and N_2O.

IFSD Model

The IFSD Model projects annual energy demand by fuel type and by sector in each province of Canada under alternative economic growth, energy prices, and other assumptions. Below is a list of the sectors for which energy demands are calculated.

- residential
- commercial
- public administration
- industrial
- transportation

Model Structure

The model consists of econometrically estimated behavioural equations based on the historical relationships between sectoral energy intensities and a set of explanatory variables, which include demographic and economic factors. It adopts a top-down approach. First, it estimates total tertiary energy demand by region and by sector. Tertiary (output) energy demand is defined as secondary (input) energy demand times the efficiency of the conversion process. Then, it determines fuel market shares and applies these shares to total tertiary energy demand to estimate secondary fuel demand.

A review of how sectoral energy demands are determined in the IFSD model is presented below.

Residential, Commercial and Public Administration Sectors

Total tertiary energy demand for these sectors is postulated to be a function of past demand, heating degree days, the weighted average price of energy and a number of economic and demographic variables. For the residential sector, these variables are real disposable income per household and the number of households. For the commercial sector capital stock in dollar terms and expected growth are key determinants.

Industrial sector

The IFSD framework allows estimation of energy consumption for the following 10 major industries:

- pulp and paper
- iron and steel
- smelting and refining
- cement
- petroleum refining
- chemicals
- other manufacturing industries
- mining
- forestry
- construction

This disaggregated analysis adds the flexibility of addressing changes in the production mix of the industrial sector as well as specific technological (from end-use models) and productivity developments.

The approach used for most industries consists of estimating energy intensity (industry energy demand divided by industry gross output) as a function of real energy prices and capital productivity.

Once tertiary demand has been calculated in each sector or sub-sector, it is disaggregated into three major fuel types- natural gas, electricity and fuel oil distillates (light fuel oil and kerosene in the residential sector, heavy fuel oil in the commercial and industrial sectors). The disaggregation is accomplished through market share equations which are specified as functions of relative fuel prices, heating degree days, and non-price variables. This estimation captures inter-fuel substitution resulting from projected changes in relative fuel costs.

The residual share (5-20 percent of the total, depending on the sector) is allocated among the remaining fuels exogenously (by informed judgement).

Market shares are multiplied by total tertiary demand in each sector to derive individual tertiary fuel demands. These are then divided by their end-use efficiencies to obtain projections of secondary demand for fuels (ie. amounts actually purchased).

Transportation Sector

In the transportation sector, the projection of energy demand for road vehicle use is carried out on a more disaggregated basis. IFSD models separately gasoline and diesel fuel consumption. Demand for alternative fuels – propane, natural gas, methanol, ethanol and electricity – are supplied by another NRCan branch, based on the economics of these fuels relative to gasoline, and other non-financial factors, such as fuel availability.

Both gasoline and diesel demands are estimated separately for passenger cars and trucks. For each type of vehicle and fuel used, demand is based on a projection of the stock of vehicles, the average fuel efficiency and the average distance travelled per vehicle. The following relationships are assumed in the model:

- the stock of vehicles on the road is obtained by applying survival rates to previous years sales of new vehicles;

- new car/truck sales are based on the cost of financing, real gasoline price, and a macro variable (real personal disposable income for passenger cars and total GDP for trucks);

- average distance travelled is a function of the price of fuel per kilometre and a macro variable (same as above); and,

- new car/truck fuel efficiency is either exogenously determined or estimated on the basis of past and current gasoline prices.

For diesel, estimates are made for two truck size classes: light/ medium trucks (under 15 000 kg), and heavier trucks.

The demand for aviation fuel is projected as a function of the demand for air travel, the price of aviation fuel, aircraft load factors and aircraft energy efficiency.

Fuel demands in the rail and marine sub sectors are based on equations which reflect expected economic growth and fuel prices.

Calibration of IFSD/End Use Models

EPB and EEB go through a long consultative process to ensure that the IFSD and the detailed end-use model results are consistent. This involves reviewing trends in the housing market, changes in regulations and standards and their impact on energy demand, evolving technological changes, etc.

CANPLAN Model

The CANPLAN model, developed by the National Energy Board, analyses on a provincial basis, the energy requirements generated by the IFSD model and projects annual peak loads to be met. The model produces a generation expansion plan and calculates the associated input energy requirements by fuel type and related gas emissions.

Based on independent analyses and available information, the contributions of minor utilities, industrial self-generation or small independent power producers are provided exogenously to the model data bank. CANPLAN analyses the residual electricity requirements that must be met by the major utilities.

CANPLAN provides the capacity additions plan required to meet the utilities peak demand and calculates annual energy production using available generating units. Based on surplus generating capacity, relative fuel costs and interconnections capabilities, the model determines the level of economy (interruptible) interchanges between provinces and/or exports to the U.S.

The results from CANPLAN are transferred into the IFSD model to complete the analysis on energy requirements.

Oil and Natural Gas Supply Model

Unlike energy demand, for which econometric techniques are available, the approach to projecting oil and natural gas supply is more eclectic. The model generates the oil and natural gas projections by ensuring that projected supply can be achieved with funds available to the industry. It does this by relating production, on a year by year basis, to reinvestment of industry cashflow and replacement costs of reserves. In addition, the supply and financing assumptions of megaprojects, including the call on industry cashflow, are considered within the model framework. The model simulation involves the following main steps:

- the estimation of industry investment for petroleum exploration and development on the basis of the reinvestment ratio and the level of industry cashflow;
- the calculation of investment available for exploration and development activities (total investment less the call on cashflow for megaprojects);
- the projection of oil and natural gas reserve additions given the assumptions on replacement costs and available cashflow; and,
- the calculation of future production from established reserves, reserves additions and megaprojects.

Estimation of CO_2 and Other Emissions

CO_2 emission factors are applied to energy demand to estimate total emissions of CO_2. These factors are agreed upon by both NRCan and Environment Canada. Since the amount of carbon in various fuels is determined by their chemical composition, CO_2 emission factors are known within a few percentage points. Other types of emissions are very dependent on the technology and hence have a high degree of uncertainty.

Annex B

Measuring the Impact of Initiatives

B.1 Initiatives in the End-Use Sector

An important component of Canada's Energy Outlook is the assessment of the impact of energy efficiency initiatives on energy use. The assessment accounts for the incremental impact of the energy efficiency initiatives of federal and provincial governments, energy utilities and municipalities, from the base year (1995) on. This implies that the "impact" (including the energy efficiency initiatives found in the Voluntary Challenge and Registry) does not include the impact of initiatives prior to 1996, the effect of which is already included in the actual level of energy use reported for 1995.

The assessment of the impact of energy efficiency initiatives requires :

- an understanding of the characteristics of the initiatives - i.e., the inputs (i.e., financial and human resources) and the outputs (i.e., brochures, regulations) of each initiative;

- the translation of information about initiatives into a judgment about their market effect - i.e., industry action, decision by vehicle owner or change in behaviour of energy consumers; and

- the calculation of the ultimate impact on energy use of the initiatives, given the market effect.

The implementation of each step of this *three step process* is described below.

A. **Information about end-use energy efficiency initiatives in Canada**

Information on end-use energy efficiency initiatives for the Outlook project was gathered from the following sources:

- NRCan's *Directory of Efficiency and Alternative Energy Programs* for federal, provincial and gas utilities' initiatives;
- National Energy Board survey of electric utility initiatives;
- the Federation of Canadian Municipalities database as well as consultations with the 20 percent club, the International Council for Local Environmental Initiatives and Cities for Climate Protection Campaign for municipal programs; and
- the Voluntary Challenge and Registry maintained by Natural Resources Canada.

This information collection exercise produced a list of thousands of programs which were then screened according to two broad criteria meant to include only initiatives that were:

- aimed at *improving energy efficiency;* and,
- expected to produce a *direct impact on energy use.*

The result of the screening was a short list of initiatives *categorized* by type, region and end-use to facilitate the assessment of effectiveness in specific target markets. From the list, *major drivers* of the initiatives impact were identified; the impact assessment is based on prospects for these major drivers.

As an example of the data gathering and screening process, in the residential sector over 70 initiatives were screened in. The most prevalent type of residential initiative was found to be the voluntary type (i.e., information, persuasion...) accounting for 60 percent of all screened in initiatives; followed by R&D initiatives (21 percent), regulation (12 percent) and financial incentives (8 percent).

After a thorough review of residential initiatives, it was concluded that building codes and minimum standards for energy consuming equipment were the major drivers of the initiative impact for new houses and new equipment respectively. As for the existing stock of houses, information type initiatives were judged to be the major determinant of the impact. Based on this information, assumptions about the effect of residential initiatives on major levers in the residential end-use model were developed reflecting the prospects for the initiatives identified as major drivers.

B. **Assessing the effectiveness of end-use energy efficiency initiatives**

In an end-use model, our judgement about the market effect of initiatives is generally expressed as an assumption about energy intensity/efficiency or the share of a market affected by initiatives. To the extent possible, these assumptions are based on hard facts gathered either from past experience or from knowledge about the short term prospects for an initiative (e.g., the level of an energy efficiency standard).

Taking household refrigeration energy use as an illustration, it is judged that the suite of measures affecting this segment of energy use over the projection period would improve the unit energy efficiency of new refrigerators by 35 percent from 1994 to 2020. This improvement is in contrast to the projection of no improvement in the efficiency of new refrigerators in the absence of energy efficiency initiatives in the residential sector.

C. **Assessing the market impact of end-use energy efficiency initiatives**

The final step of the impact assessment consists of running the end-use models with assumptions reflecting the market effect of programs. The level of detail of the assumptions varies according to the detail available in the different models. In the residential sector for example, it is possible to make specific assumptions about the efficiency of new refrigerators while in the industrial sector new and existing stock are not explicitly identified and any impact on new stock must be translated into its impact on total stock outside the model before input.

As a final check on the reasonableness of the initiatives impact, estimates are checked against the results of studies of the potential for energy efficiency gains. This check ensures that the impact estimate lies within reasonable bounds, in light of the types of initiatives and their potential to realize energy efficiency opportunities available on the market.

Some Important Assumptions

There are important assumptions underlying the assessment of energy efficiency initiatives. While some of these may be obvious from the foregoing, they are repeated here for clarity.

Incrementality

The impact assessment requires that a scenario of energy use without the impact of end-use energy efficiency initiatives (the basic scenario) be developed. At NRCan this is done through a reconciliation of the results of the top-down Inter-Fuel Substitution Demand (IFSD) model with results of separate end-use models for the residential, commercial and industrial sectors. For the transportation sector, only the transportation module of the IFSD Model is used in the impact assessment.

Assessing the impact of initiatives against a business as usual scenario allows for the characterization of the resulting impact as incremental. This is an important assumption since it suggests that the nature of the business as usual scenario will have a bearing on the absolute size of the initiatives impact. In other words, the more optimistic the basic scenario in terms of energy efficiency gains, the less room will be left for the impact of initiatives.

Attribution of impacts to specific initiatives

Another crucial assumption underlying the assessment of initiatives impact relates to the attribution of impacts to specific initiatives. In the assessment prepared for the energy Outlook we have estimated the impact of a set of initiatives on a given segment of energy use. For example, rather than measuring the specific impact of the EnerGuide Program on refrigerator energy use, the combined impact of all initiatives (regulation, R&D, financial incentives and information) aimed at this segment of energy use is evaluated.

Our approach to the attribution of impacts is based on the following observations:

- many initiatives were designed to be complementary and disentangling their effect on energy use would be creating an artificial result;

- there exists very little historical information about the effectiveness of past programs on which to base initiative specific program impacts; and,

- any attempt to estimate initiative specific impacts would be fraught with the potential for double counting.

Funding of end-use energy efficiency initiatives

For the purpose of the impact assessment it has been assumed that base funding for all of the initiatives in existence in the base year is continued throughout the projection period.

B.2 Estimating the VCR Actions of Energy Producing Industries

In addition to the initiatives related to the final consumption of energy, the Voluntary Challenge and Registry (VCR) contains a number of action plans submitted by producers of fossil fuels and producers of electricity. The impacts of these plans have been incorporated in the Outlook. A methodology has been developed to estimate the likely impact of further reduction in emissions beyond the time frame (typically to 2000) of most action plans. The approach used to incorporate these VCR action plans and to estimate their impacts on GHG emissions is described below.

Fossil Fuel Producers

Inventory Estimates

One of the problems in estimating emissions reductions from the upstream oil and gas industry is the accuracy of the base year inventory estimates. We assume that Statistics Canada's Quarterly Report on Energy Supply and Demand captures all of the fuel used in the production of oil and gas.

Although estimates of carbon dioxide (CO_2) emissions from fuel combustion are reasonably accurate, fugitive emissions (methane) present a more difficult problem as the only available continuous measurements of methane are those related to industrial processes. The fugitive emissions, largely leaks from valves, controllers, regulators, pumps, and producing wells, are not measured but rather estimated from a few sample studies. Unlike carbon dioxide emissions, there are no yearly measured data for methane, and the Environment Canada inventory estimates are based solely on production data and constant emission factors. These estimates are based on two studies, one prepared in 1992[1], based on 1989 data, for the Canadian Petroleum Association (CPA), now the Canadian Association of Petroleum Producers (CAPP), and one prepared in 1994[2] for the Canadian Gas Association (CGA). The latter study is being updated, and the results are not yet known.

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1 A Detailed Inventory of CH_4 and VOC Emissions From Upstream Oil and Gas Operations in Alberta, Volumes I - III, prepared for the Canadian Petroleum Association by Clearstone Engineering Ltd., March, 1992.

2 1990 Air Emissions Inventory for the Canadian Gas Association. published March, 1995.

The estimates presented below are based the fact that there is significant potential to reduce methane emissions from heavy oil production. Methane from heavy oil production is normally vented to the atmosphere, while in the case of light oil wells it is captured or flared. The estimated reductions in emissions are very dependent on the current inventory estimates.

Carbon Dioxide Emissions

A. Upstream Oil & Gas Production

The VCR submissions or action plans of many companies have been examined, with particular emphasis on those of CAPP and the major oil and gas companies[3]. The reductions in carbon dioxide emissions are based on the fuel efficiencies projected largely in the non-conventional oil and in the gas processing segments of the industry. The reductions for the synthetic plants are based on the detailed submissions of both Suncor and Syncrude[4]. For heavy oil production the efficiency gains are estimated at about 1 per cent per year.

B. Pipelines

Both major transmission and distribution pipelines are significant fuel consumers accounting for 245 PJ in 1995, similar to that of the iron and steel industry. Based on the VCR submissions by the major pipeline and distribution companies the fuel use has been projected to decline by about 1 percent per year, starting in 1998.

Methane Emissions

A. Upstream Oil & Gas Production

The latest VCR submission by CAPP (1996) suggests that over the past several years many companies concentrated on fuel combustion efficiency improvements and the reductions in methane emissions have not been documented. Environment Canada's estimates of methane emissions are based on production and constant emission factors. To adjust for the recent

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3 These include all of the major oil and gas companies and all of the major pipelines.

4 The emission reductions are detailed by year in the synthetic plants action plans, with Suncor projecting a decline of 24 percent by 2000, and Syncrude a decline of 14 percent. Both companies' emissions are projected to be similar per unit of production by 2010, and no further reductions are anticipated after that year.

past companies' actions, the emission factors for the period 1991-1995 were reduced by 5 percent. A similar approach has been used to adjust the methane emissions for the forecast period. The Chart below shows the detailed rates used to estimate methane reductions. Given our assumptions about the natural gas prices and under a normal rate of return, the reduction in methane emissions has been limited to a maximum of 40 per cent.

Chart - Methane Emission Reduction Rates by Source and Time Period

	1991-1995	1995-2000	2000-2005	2005-2020
Categories:	Percent reductions per year			
Drilling, well-service, gas production and processing, Transport	1.0	3.0	3.0	1.0
Light Oil Production	1.0	4.0	4.0	0.7
Heavy Oil Production	1.0	6.0	4.0	0.0
Bitumen Production	0.7	2.0	2.0	1.0

B. Pipelines

Pipeline methane emissions have been reduced by 1.1 percent per year from 1991 to 1996, by 6.8 percent per year from 1996 to 2000, and by 0.5 percent per year after 2000. Emission reductions were again capped at about 40 percent. The 1996-2000 emission reductions follow the path indicated in the VCR submissions of TransCanada Pipelines, Centra Gas Alberta and Consumers Gas, capturing the essence of their VCR programs.

Electric Utilities

Based on targets established by provincial utilities and the Canadian Electricity Association (CEA) 1996 progress report, the impact of VCR has been estimated at 3.3 Mt of CO_2 in 2000. The Outlook, following discussion with CEA representatives, assumes no additional impact for the period of 2001 to 2020.

Annex C

Projection Results - Canada Tables

Annex C

Macroeconomic Assumptions

Canada

Code		1990	1994	1995	2000	2005	2010	2015	2020	Annual Growth 1995-2020
					Projection					
	REAL DOMESTIC PRODUCT (RDP): ($1986 MILLIONS)									
RDPC	TOTAL	503136	531619	542182	605371	673639	749500	836322	926169	2.16
RDPAGC	AGRICULTURE	10838	11126	11063	12238	13381	14867	16746	18931	2.17
RDPINC	TOTAL INDUSTRIAL	148193	151218	156740	182372	202789	223267	245653	269291	2.19
RDPCPC	COMMERCIAL & PUBLIC ADMIN.	284239	303592	284389	309952	345879	388015	436988	487185	2.18
RDPAVC	AVIATION	2581	2018	2094	2260	2437	2647	2876	3089	1.57
RDPRLC	RAIL	3958	4387	4461	4579	4667	4772	4909	5072	0.51
	INDUSTRIAL GROSS OUTPUT($1986 MILLIONS)									
GOTPPC	PULP & PAPER	23992	25289	26817	28475	31386	34639	38065	40930	1.71
GOTCHC	CHEMICAL	8895	8053	8948	10221	11668	13326	15297	17243	2.66
GOTISC	IRON & STEEL	7292	7407	7548	8045	8548	9009	9519	10031	1.14
GOTSRC	SMELTING & REFINING	8146	9984	10250	11029	12680	14013	15420	16800	2.00
GOTMIC	MINING	37826	44634	47325	50247	53942	56088	57689	59681	0.93
GOTOMC	OTHER MANUFACTURING	219892	240668	260906	328437	375991	422393	470275	521586	2.81
GOTCOC	CONSTRUCTION	84757	71672	69082	80829	90106	100315	112343	124168	2.37
GOTFOC	FORESTRY	7793	8111	8390	8612	9417	10155	10947	11531	1.28
GOTCMC	CEMENT	894	665	709	765	835	896	985	1134	1.90
GOTPRC	PETROLEUM REFINING	16660	17140	18353	18817	19776	20785	21846	22960	0.90
	REAL PERSONAL DISPOSABLE INCOME ($1986 MILLIONS)									
YPDKC	PERSONAL DISPOSABLE INCOME	383383	387201	391038	413469	453680	497847	554484	615612	1.83
YPDPCC	PER CAPITA ($1986)	13795	13238	13208	13320	13987	14742	15737	16717	0.95
YPDHHC	PER HOUSEHOLD ($1986)	39836	37348	37061	36790	37942	39128	40593	42255	0.53
	PRICES AND COSTS: (1986=1.0)									
PWPIUS	U.S. PRODUCER PRICE (1982=100)	119.1	125.5	128.6	147.3	165.3	186.6	212.8	237.7	2.49
PGDP	GDP DEFLATOR - TOTAL	1.133	1.239	1.291	1.376	1.492	1.592	1.712	1.833	1.41
PGDPIN	INDUSTRIAL	1.163	1.174	1.177	1.193	1.209	1.225	1.241	1.256	0.26
PGDPCP	COMMERCIAL	1.216	1.291	1.296	1.321	1.346	1.371	1.396	1.421	0.37
CPI	**CONSUMER PRICE INDEX**	1.195	1.307	1.335	1.464	1.631	1.77	1.916	2.07	1.77
	DEMOGRAPHIC: ('000)									
POPC	TOTAL POPULATION	27791	29251	29606	31042	32436	33770	35234	36825	0.88
HHC	TOTAL HOUSEHOLDS	9624	10387	10551	11239	11957	12724	13660	14569	1.30
	LABOUR MARKET:									
LFC	LABOUR FORCE ('000)	14329	14832	14927	15903	16840	17590	18152	18584	0.88
EMPC	TOTAL EMPLOYMENT ('000)	13165	13291	13505	14313	15202	15940	16639	17102	0.95
URATEC	UNEMPLOYMENT RATE (%)	7.97	11.18	9.53	10	9.73	9.38	8.33	7.97	-0.71
RDPPEC	LABOUR PROD. (RDP/EMP) $1986	32240	34111	40145	42295	44313	47020	50262	54154	1.20
DDAYSC	**HEATING DEGREE DAYS (NORM=1)**	0.925	0.986	0.979	0.972	0.972	0.972	0.972	0.972	-0.03

Annex C

World and Domestic Crude Oil Prices ($/Barrel)

		1990	1994	1995	2000 (Projection)	2005 (Projection)	2010 (Projection)	2015 (Projection)	2020 (Projection)
	WEST TEXAS INTERMEDIATE: ($US)								
MWTCU	CUSHING	24.48	17.16	18.45	22.90	25.71	29.01	33.10	36.97
PWTCUR	REAL ($1995) $/BBL	24.96	17.16	18.45	20.00	20.00	20.00	20.00	20.00
MOCUCH	TRANSPORTATION TO CHICAGO	0.60	0.58	0.59	0.63	0.67	0.71	0.76	0.80
MWTCH	CHICAGO	25.08	17.74	19.04	23.53	26.38	29.72	33.85	37.77
	BRENT ($US)								
MBRNS	NORTH SEA (F.O.B)	23.86	15.82	17.03	21.25	23.91	27.03	30.89	34.56
MOLOSS	OCEAN LOSS	0.10	0.06	0.07	0.09	0.10	0.11	0.12	0.14
MONSPO	TRANSPORTATION TO PORTLAND	0.91	0.84	0.85	0.91	0.96	1.02	1.09	1.15
MOPOMO	TRANSPORTATION TO MONTREAL	0.73	0.57	0.58	0.62	0.65	0.70	0.74	0.79
MBRMO	MONTREAL (C.I.F)	25.60	17.29	18.52	22.86	25.62	28.86	32.85	36.63
	CANADIAN PAR:								
MPACH	CHICAGO ($US)	24.99	17.16	18.85	23.29	26.11	29.42	33.52	37.39
MRFPAU	U.S. IMPORT TARIFFS	0.21	0.12	0.13	0.13	0.13	0.13	0.13	0.13
MOBOCH	TRANSPORTATION TO U.S. BORDER	0.47	0.55	0.56	0.60	0.63	0.67	0.72	0.76
MOBOED	TRANSPORTATION TO EDMONTON	0.55	0.55	0.56	0.58	0.61	0.64	0.67	0.69
MPAED	EDMONTON ($CDN)	27.67	21.85	24.17	29.09	31.77	34.19	37.29	39.87
	REFINERY CRUDE COST ($CDN):								
MCRATA	ALBERTA	27.67	21.85	24.17	29.09	31.77	34.19	37.29	39.87
MCRATO	ONTARIO	27.21	21.57	25.36	30.79	33.52	36.04	39.19	41.89
MCRATQ	QUEBEC	28.34	22.30	25.49	31.03	33.76	36.30	39.45	42.18
MCRATF	ATLANTIC	28.34	22.30	23.36	27.92	30.42	32.64	35.50	37.88

Domestic and Export Natural Gas Price ($/Mcf)

		1990	1994	1995	Projection 2000	2005	2010	2015	2020
	DOMESTIC PRICE AT ALTA. BORDER:								
MRNGAB	AVERAGE REAL ($1995)	2.05	2.15	1.67	1.96	2.02	2.08	2.07	2.06
MNGAB	AVERAGE NOMINAL	1.85	2.10	1.67	2.15	2.46	2.76	2.97	3.19
MNGABR	RESIDENTIAL	2.04	2.02	1.86	2.40	2.77	3.11	3.36	3.62
MNGABC	COMMERCIAL	1.98	2.02	1.78	2.30	2.66	2.99	3.23	3.48
MNGABI	INDUSTRIAL (DIRECT SALES)	1.64	2.15	1.49	1.92	2.22	2.49	2.69	2.90
MOPAR	TORONTO GAS/OIL PARITY	0.62	0.89	0.67	0.66	0.67	0.68	0.67	0.67
	EXPORT PRICE AT US BORDER:								
MNGXT	NOMINAL ($CDN)	2.27	2.58	1.80	2.25	2.56	2.85	3.07	3.29
MNGXU	NOMINAL ($US)	1.95	1.89	1.31	1.70	2.00	2.34	2.63	2.95
	REAL AVERAGE FIELD GATE PRICE ALL CANADIAN & EXPORT SALES								
PNGFIR	($1995CDN)/MCF	1.75	1.90	1.35	1.65	1.73	1.80	1.80	1.80
PHHFIR	HENRY HUB ($1995CDN)/MCF	2.15	2.60	2.25	2.55	2.65	2.70	2.70	2.70
PHHFIR	HENRY HUB ($1995 U. S.)/MCF	1.85	1.90	1.65	1.90	1.98	2.05	2.05	2.05

Energy Prices - Thermal Units ($/Gigajoule)

		1990	1994	1995	2000 (Projection)	2005 (Projection)	2010 (Projection)	2015 (Projection)	2020 (Projection)
	ENERGY PRICE INDEXES (1986=1.0)								
PDIRAC	RESIDENTIAL	1.57	2.09	2.12	2.30	2.51	2.73	2.95	3.19
PDICPC	COMMERCIAL	1.64	1.69	1.70	1.83	1.99	2.17	2.35	2.54
PDIINC	INDUSTRIAL	1.42	1.67	1.63	1.73	1.84	2.01	2.17	2.34
PDITRC	TRANSPORTATION	1.58	1.47	1.59	1.82	2.00	2.16	2.34	2.52
PDISDC	TOTAL SECONDARY DEMAND	1.54	1.71	1.74	1.90	2.07	2.24	2.43	2.61
	REGIONAL SECTORAL PRICES: ($/GJ - EFFICIENCY ADJUSTED)								
PULFRC	LFO - RESIDENTIAL	14.23	13.71	15.28	16.62	16.75	17.08	18.67	20.15
PULFCC	- COMMERCIAL	11.27	10.93	10.80	12.39	13.68	14.83	16.12	17.34
PUHFIC	HFO - INDUSTRIAL	3.55	3.88	4.33	5.20	5.63	6.06	6.59	7.04
PUHFCC	- COMMERCIAL	3.94	4.19	4.58	5.52	6.03	6.49	7.07	7.55
PUNGRC	NATURAL GAS - RESIDENTIAL	7.24	7.89	7.68	8.60	9.11	9.31	9.91	10.51
PUNGCC	- COMMERCIAL	5.15	6.06	5.91	6.92	7.79	8.57	9.26	9.99
PUNGIC	- INDUSTRIAL	3.17	3.52	2.86	3.47	3.92	4.32	4.64	4.97
PUELRC	ELECTRICITY - RESIDENTIAL	14.55	22.12	22.43	23.64	25.60	27.76	30.06	32.50
PUELCC	- COMMERCIAL	18.64	18.95	19.26	20.15	21.73	23.59	25.54	27.61
PUELIC	- INDUSTRIAL	10.57	13.18	13.37	13.56	14.10	15.31	16.58	17.91
	PRICE RATIOS: (EFFICIENCY ADJ'D)								
	RESIDENTIAL:								
RPEORC	ELECTRICITY / LIGHT FUEL OIL	1.02	1.61	1.47	1.42	1.53	1.63	1.61	1.61
RPEGRC	ELECTRICITY / NATURAL GAS	2.01	2.80	2.92	2.75	2.81	2.98	3.03	3.09
RPOGRC	LIGHT FUEL OIL / NATURAL GAS	1.97	1.74	1.99	1.93	1.84	1.83	1.88	1.92
	COMMERCIAL:								
RPEOCC	ELECTRICITY / LIGHT FUEL OIL	1.65	1.73	1.78	1.63	1.59	1.59	1.59	1.59
RPEGCC	ELECTRICITY / NATURAL GAS	3.62	3.13	3.26	2.91	2.79	2.75	2.76	2.76
RPOGCC	LIGHT FUEL OIL / NATURAL GAS	2.19	1.80	1.83	1.79	1.76	1.73	1.74	1.74
	INDUSTRIAL:								
RPEOIC	ELECTRICITY / HEAVY FUEL OIL	2.98	3.40	3.09	2.61	2.50	2.53	2.52	2.54
RPEGIC	ELECTRICITY / NATURAL GAS	3.33	3.74	4.67	3.91	3.60	3.54	3.57	3.60
RPOGIC	HEAVY FUEL OIL / NATURAL GAS	1.12	1.10	1.51	1.50	1.44	1.40	1.42	1.42

Annex C

Light and Heavy Crude Oil Balances (Thousands of Barrels per day)

		1990	1994	1995	2000	2005	2010	2015	2020
					Projection				
	LIGHT CRUDE OIL:								
MQLMPN	CONVENTIONAL (INCL. E.O.R.)	894.2	915.6	907.4	851.6	797.8	749.6	705.7	640.0
MQSOPN	SYNTHETIC	208.3	261.8	279.4	304.4	349.3	399.3	424.2	449.2
MQCRFR	FRONTIERS	0.0	22.7	19.9	134.9	214.8	199.8	199.8	199.8
MQPPPN	PENTANES	115.8	156.1	154.8	195.0	204.7	212.6	219.4	227.6
MQLPDL	LESS DILUENT REQUIREMENTS	86.0	89.4	103.0	132.5	158.5	180.3	200.9	197.5
MQCRUP	UPGRADER OUTPUT	44.1	94.4	94.4	94.4	94.4	94.4	94.4	94.4
MQCTLT	TOTAL SUPPLY	1186.4	1352.3	1353.0	1447.7	1502.5	1475.3	1442.7	1413.5
MVCRDD	TOTAL DOMESTIC DEMAND	1446.7	1416.5	1407.7	1463.4	1534.4	1618.1	1720.6	1789.0
MVHVDD	LESS: DEMAND FOR HEAVY	78.3	86.4	89.3	94.5	97.4	99.8	102.5	105.4
MVLMDD	DOMESTIC DEMAND FOR LIGHT	1393.1	1376.7	1377.0	1368.8	1437.0	1518.2	1618.1	1683.6
	SUPPLY/DEMAND BALANCE FOR								
MVLMSD	LIGHT OIL AND NET IMPORTS	536.2	622.4	590.9	840.3	801.7	827.2	859.5	857.7
MVLMXS	LIGHT OIL EXPORTS	247.9	539.3	538.7	817.3	771.6	694.9	601.6	512.1
	HEAVY CRUDE OIL:								
MQHVPN	CONVENTIONAL (INCL. E.O.R.)	313.4	406.5	456.9	507.4	518.1	503.1	478.6	434.6
MQOCNT	IN-SITU AND BITUMEN	129.6	134.7	149.1	199.5	246.1	295.8	346.1	396.5
MQCRUC	LESS: UPGRADER INPUT-CONV	44.1	75.5	75.5	75.5	75.5	75.5	75.5	75.5
MQCRUB	UPGRADER INPUT-BITUMEN	0.0	25.2	25.2	25.2	25.2	25.2	25.2	72.3
MQLPDL	DILUENT (PENTANES AND OTHER)	86.0	89.4	103.0	132.5	158.5	180.3	200.9	197.5
MQCTHV	TOTAL SUPPLY	489.0	519.1	608.3	738.7	822.0	878.5	924.9	924.8
MVHVDD	DEMAND FOR DOMESTIC HEAVY	78.3	86.4	89.3	94.5	97.4	99.8	102.5	105.4
	SUPPLY/DEMAND BALANCE								
MVHVXS	(EXPORTABLE SURPLUS)	406.6	443.5	519.1	644.1	724.6	778.6	822.3	819.4

Annex C

Supply and Demand - Petroleum (Thousands of Barrels per day)

					Projection					Annual Growth
		1990	1994	1995	2000	2005	2010	2015	2020	1995-2020
	DOMESTIC CRUDE OIL PRODUCTION:									
MVCRPN	TOTAL	1667.9	1897.3	1961.5	2186.4	2324.5	2353.8	2367.6	2338.4	0.71
MQCROO	- CONVENTIONAL OLD OIL	343.0	193.2	173.7	104.5	62.3	40.0	25.2	17.1	
MQSOPN	- SYNTHETIC OIL	208.3	261.8	279.4	304.4	349.3	399.3	424.2	449.2	
MQCRER	- ENHANCED RECOVERY	126.5	126.5	127.1	163.0	171.8	185.6	173.1	163.0	
MQCRNT	- NEW OIL	991.8	1307.0	1387.6	1620.9	1747.4	1735.2	1751.3	1718.4	
MQCRUN	- NET HEAVY UPGRADING	0.0	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-9.3	
	DOMESTIC CRUDE OIL DEMAND:									
MVRPDD	PETROLEUM PRODUCTS DEMAND	1509.7	1502.7	1519.1	1527.8	1602.5	1690.6	1798.6	1870.5	0.84
MVCRRG	REFINERY GAIN AND ADJUSTMENTS	74.3	95.0	99.4	76.4	80.1	84.5	89.9	93.5	
MQLPRN	NET REFINERY PROD'N OF LPGs	12.0	8.8	12.0	12.0	12.0	12.0	12.0	12.0	
MQLPPR	- TOTAL REFINERY LPG PROD'N	38.8	35.9	39.0	39.0	39.0	39.0	39.0	39.0	
MVLPRP	- REFINERY LPG CONSUMPTION	27.1	27.1	27.1	27.1	27.1	27.1	27.1	27.1	
MVCRDD	DOMESTIC CRUDE OIL DEMAND	1446.7	1416.5	1407.7	1463.4	1534.4	1618.1	1720.6	1789.0	
	PETROLEUM EXPORTS:									
MVPEXT	TOTAL	895.5	1218.9	1308.3	1711.9	1746.6	1724.0	1674.4	1582.0	0.76
MVCRXT	- CRUDE OIL - TOTAL	654.5	982.9	1057.8	1461.4	1496.2	1473.6	1424.0	1331.6	
MVLMXS	- LIGHT & MEDIUM	247.9	539.3	538.7	817.3	771.6	694.9	601.6	512.1	
MVHVXS	- HEAVY (INCL. DILUENT)	406.6	443.5	519.1	644.1	724.6	778.6	822.3	819.4	
MVCRXE	- EXCHANGES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
MVRPXT	- PRODUCTS - TOTAL	241.0	236.0	250.5	250.5	250.5	250.5	250.5	250.5	
	PETROLEUM IMPORTS:									
MVPEMT	TOTAL	679.0	752.0	733.1	988.9	956.5	988.3	1027.5	1032.6	1.38
MVLMSD	- CRUDE OIL	536.2	622.4	590.9	840.3	801.7	827.2	859.5	857.7	
MVRPMT	- PRODUCTS - TOTAL	142.8	129.6	142.2	148.5	154.8	161.1	168.0	174.9	
MVPEMN	NET PETROLEUM IMPORTS	-220.9	-468.8	-553.8	-723.0	-790.1	-735.7	-646.9	-549.4	

Annex C

Supply and Demand - Natural Gas & NGLs

		1990	1994	1995	Projection 2000	2005	2010	2015	2020	Annual Growth 1995-2020
	NATURAL GAS: (BILLIONS OF CUBIC FEET)									
MVNGPN	TOTAL PRODUCTION	3494	4898	5227	5751	6085	6356	6601	6907	1.12
MVNGDD	DOMESTIC DEMAND	2024	2370	2457	2679	2813	2884	3039	3235	1.11
MVNGSC	STOCK CHANGE	57	43	0	0	0	0	0	0	
MVNGXT	EXPORTS	1436	2521	2794	3100	3300	3500	3590	3700	
MVNGMT	IMPORTS	23	37	24	28	28	28	28	28	
	NATURAL GAS DISTRUBITION									
MKGDSC	CAPACITY	30	31	31	33	33	34	34	34	
	GAS PLANT NGLs: (THOUSAND BARRELS PER DAY)									
MQLPRN	NET REFINERY PRODUCTION	11.96	8.81	11.96	11.96	11.96	11.96	11.96	11.96	
MVGPPN	GAS PLANT PROD (EXCL SOL FLD)	300.17	390.72	489.12	488.59	516.97	539.98	560.8	586.78	0.73
MVPBPN	PROPANE & BUTANE	178.72	235.29	289.85	289.54	306.35	319.99	332.33	347.72	
MVETPN	ETHANE	121.45	155.43	199.27	199.06	210.62	219.99	228.47	239.06	
MVGPDD	DOMESTIC DEMAND	186.27	234.09	206.51	273.72	285.66	307.2	310.68	314.09	
MVGPSC	STOCK CHANGE	8.18	23.28	0	0	0	0	0	0	
MVGPXT	NET EXPORTS (POTENTIAL)	117.05	152.22	294.57	226.83	243.26	244.73	262.07	284.65	

Electricity Supply and Demand (Gigawatt hours)

Canada

		1990	1994	1995	2000 (Projection)	2005 (Projection)	2010 (Projection)	2015 (Projection)	2020 (Projection)	Annual Growth 1995-2020
	GENERATING CAPACITY (MEGAWATTS).									
KEGCTC	TOTAL	102469	109862	108358	110269	111500	114299	117861	127564	0.65
KEGCUC	UTILITIES	96132	102118	100264	100434	100305	102503	105816	115006	0.55
KEGCIC	INDUSTRIES	6130	6621	6648	6657	6657	6656	6649	6867	0.13
KEGCPC	INDEPENDENT POWER PRODUCERS	207	1123	1446	3178	4538	5140	5396	5691	5.63
	TOTAL GENERATION (GIGAWATTS HOURS)									
VELPNC	TOTAL	466721	536147	537160	557267	583029	600575	625503	661357	0.84
VEUPNC	UTILITIES	425466	485809	485665	492052	507971	520999	544096	578102	0.70
VEIPNC	INDUSTRY	40015	43188	42781	43522	43522	43522	43517	43522	0.07
VEPPNC	INDEPENDENT POWER PRODUCERS	1240	7150	8714	21693	31536	36054	37890	39733	6.26

Note: 1994 data subject to small adjustments.

Annex C — Summary Results - Energy Demand (Petajoules) — Canada

		1990	1994	1995	2000 (Projection)	2005 (Projection)	2010 (Projection)	2015 (Projection)	2020 (Projection)	Annual Growth 1995-2020
	END USE DEMAND BY FUEL:									
MTSEUC	TOTAL END USE DEMAND	7340.2	7763.8	7966.6	8338.2	8739.7	9116.4	9609.9	10093.1	0.95
MRPEUC	RPPs	3071.9	3120.6	3175.3	3183.5	3322.5	3492.8	3713.8	3924.6	0.85
MNGEUC	NATURAL GAS	1890.7	2067.6	2146.1	2329.5	2411.5	2430.6	2511.1	2601.6	0.77
MELEUC	ELECTRICITY	1483.3	1564.0	1595.3	1629.5	1726.3	1822.0	1941.6	2053.1	1.01
MCCEUC	COAL	52.7	46.4	47.7	61.1	66.1	67.4	70.7	74.0	1.77
MLPEUC	LPGs	229.9	305.3	270.0	357.4	372.8	401.1	405.6	410.1	1.69
MKGEUC	COKE AND COKE OVEN GAS	139.9	129.0	132.9	137.5	142.3	145.6	152.0	158.9	0.72
MSTEUC	STEAM	21.0	15.0	16.6	21.4	23.1	23.8	24.7	26.1	1.83
MOFEUC	OTHER	367.9	433.9	491.8	522.4	578.3	635.8	693.5	748.8	1.70
MWDEUC	RESIDENTIAL WOOD	84.1	82.0	90.9	96.0	96.8	97.3	96.9	96.1	0.22
	END USE DEMAND BY SECTOR:									
MTSEUC	TOTAL END-USE DEMAND	7340.2	7763.8	7966.6	8338.2	8739.7	9116.4	9609.9	10093.1	0.95
MTSRAC	RESIDENTIAL	1429.9	1520.1	1511.5	1505.1	1474.9	1430.3	1453.1	1487.3	-0.06
MTSCPC	COMMERCIAL	892.7	965.9	1005.6	1019.8	1061.1	1112.6	1173.0	1238.0	0.84
MTSINC	INDUSTRIAL *	3122.2	3294.6	3424.7	3690.5	3967.1	4220.3	4480.1	4716.1	1.29
MTSTRC	TRANSPORTATION	1895.4	1983.2	2024.9	2122.9	2236.6	2353.2	2503.8	2651.7	1.08
	PRIMARY DEMAND BY SECTOR:									
HTSPDC	TOTAL PRIMARY ENERGY DEMAND	9583.6	10592.8	10971.2	11446.1	11959.6	12401.2	12910.0	13449.0	0.82
MTSEUC	END-USE DEMAND	7340.2	7763.8	7966.6	8338.2	8739.7	9116.4	9609.9	10093.1	0.95
MTSFFC	FOSSIL FUEL PRODUCERS	970.9	1167.7	1277.3	1337.3	1382.2	1398.2	1432.6	1478.1	0.59
MTSELC	ELECTRICITY GENERATION	1271.0	1658.6	1727.3	1770.7	1837.7	1886.6	1867.5	1877.8	0.33
	PRIMARY DEMAND BY FUEL									
HTSPDC	TOTAL PRIMARY ENERGY DEMAND	9583.6	10592.8	10971.2	11446.1	11959.6	12401.2	12910.0	13449.0	0.82
HRPPDC	RPPs	3277.9	3259.1	3324.7	3310.9	3473.1	3666.5	3901.8	4049.5	0.79
HNGPDC	NATURAL GAS	2694.9	3108.4	3270.6	3558.1	3718.9	3792.0	3973.9	4206.6	1.01
HLPPDC	LPGs	232.3	308.7	272.7	361.5	377.3	405.7	410.3	414.8	1.69
HCCPDC	COAL	1077.5	1085.7	1118.6	1010.5	1085.1	1205.3	1442.8	1614.8	1.48
HENPDC	NUCLEAR ELECTRICITY	796.0	1176.2	1151.7	1247.7	1251.7	1211.1	964.3	822.5	-1.34
HEHPDC	HYDRO ELECTRICITY (3.6)	1053.0	1136.5	1190.5	1241.6	1264.4	1264.5	1295.9	1356.7	0.52
HOFPDC	OTHER (RENEWABLES)	452.1	518.1	641.2	714.6	787.7	854.6	919.5	982.5	1.72
	RATIOS:									
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	141.2	138.2	134.8	126.0	115.7	104.9	99.1	94.9	-1.39
MCDPRC	COM. DEMAND / COM. RDP	1.7	1.7	1.7	1.6	1.5	1.4	1.4	1.4	-0.96
RIDPRC	IND. DEMAND / IND. RDP	16.3	16.7	17.2	15.7	15.2	14.7	14.3	13.7	-0.90
MEUPCC	END USE DEMAND/ POP (GJ)	264.1	265.4	269.1	268.6	269.5	270.0	272.8	274.1	0.07
MEUPRC	" " / RDP/	14.6	14.6	14.7	13.8	13.0	12.2	11.5	10.9	-1.19
RPDPCC	PRIMARY DEMAND / POP (GJ)	345.2	362.3	370.6	368.7	368.7	367.2	366.4	365.2	-0.06
RPDPRC	" " / RDP	19.1	19.9	20.2	18.9	17.8	16.6	15.4	14.5	-1.32

* *Includes non-combustible use.*
Note: 1994 electricity data subject to small adjustments.

Annex C

Summary Results - Energy Demand (Petajoules)

Atlantic

		1990	1994	1995	Projection 2000	2005	2010	2015	2020	Annual Growth 1995-2020
	END USE DEMAND BY FUEL:									
MTSEUC	TOTAL END USE DEMAND	568.0	554.9	571.9	588.2	618.6	644.8	682.0	710.0	0.87
MRPEUC	RPPs	381.0	362.2	366.9	370.8	386.0	399.2	421.1	441.1	0.74
MNGEUC	NATURAL GAS	0.0	0.0	0.0	1.0	1.0	1.0	1.0	1.0	
MELEUC	ELECTRICITY	108.6	115.3	117.0	117.3	124.5	130.4	138.6	140.8	0.74
MCCEUC	COAL	2.0	1.5	1.4	1.6	1.9	1.9	2.2	2.5	2.35
MLPEUC	LPGs	7.5	4.8	4.2	5.2	5.6	5.7	6.0	6.3	1.64
MKGEUC	COKE AND COKE OVEN GAS	5.0	4.4	4.5	5.4	6.4	6.5	7.2	8.1	2.38
MSTEUC	STEAM	1.4	3.1	3.1	3.7	4.5	4.5	5.0	5.6	2.39
MOFEUC	OTHER	46.0	46.8	51.2	54.8	59.9	66.2	71.1	74.3	1.50
MWDEUC	RESIDENTIAL WOOD	17.1	16.1	23.5	28.2	28.8	29.4	29.9	30.2	1.01
	END USE DEMAND BY SECTOR:									
MTSEUC	TOTAL END-USE DEMAND	568.0	554.9	571.9	588.2	618.6	644.8	682.0	710.0	0.87
MTSRAC	RESIDENTIAL	115.9	114.6	115.0	116.3	115.3	113.3	114.0	114.9	0.00
MTSCPC	COMMERCIAL	59.7	57.8	60.8	62.2	63.0	64.8	66.4	67.5	0.42
MTSINC	INDUSTRIAL *	207.7	200.9	212.6	217.7	241.2	257.5	278.1	289.7	1.25
MTSTRC	TRANSPORTATION	184.6	181.7	183.5	192.0	199.0	209.2	223.4	237.9	1.04
	PRIMARY DEMAND BY SECTOR:									
HTSPDC	TOTAL PRIMARY ENERGY DEMAND	839.4	814.4	810.2	859.3	925.4	976.5	1026.7	1045.0	1.02
MTSEUC	END-USE DEMAND	568.0	554.9	571.9	588.2	618.6	644.8	682.0	710.0	0.87
MTSFFC	FOSSIL FUEL PRODUCERS	17.3	13.0	10.9	18.9	22.8	22.0	22.0	15.5	1.42
MTSELC	ELECTRICITY GENERATION	252.9	245.4	227.5	252.3	284.0	309.8	322.8	319.4	1.37
	PRIMARY DEMAND BY FUEL									
HTSPDC	TOTAL PRIMARY ENERGY DEMAND	839.4	814.4	810.2	859.3	925.4	976.5	1026.7	1045.0	1.02
HRPPDC	RPPs	497.7	427.4	426.8	415.8	458.6	495.2	533.4	490.7	0.56
HNGPDC	NATURAL GAS	0.0	0.0	0.0	1.5	1.5	1.5	1.5	1.5	
HLPPDC	LPGs	7.3	4.4	4.2	5.2	5.6	5.7	6.0	6.3	1.64
HCCPDC	COAL	83.1	115.0	138.6	136.9	144.7	149.3	154.6	210.5	1.69
HENPDC	NUCLEAR ELECTRICITY	61.7	60.6	17.4	55.1	55.1	55.1	55.1	55.1	4.72
HEHPDC	HYDRO ELECTRICITY (3.6)	126.5	143.2	143.5	149.6	149.3	149.5	149.6	149.7	0.17
HOFPDC	OTHER (RENEWABLES)	63.2	63.9	79.8	95.2	110.6	120.2	126.6	131.3	2.01
	RATIOS:									
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	146.5	137.6	133.4	129.3	122.1	114.4	109.6	106.3	-0.91
MCDPRC	COM. DEMAND / COM. RDP	1.3	1.2	1.2	1.2	1.1	1.1	1.0	1.0	-0.87
RIDPRC	IND. DEMAND / IND. RDP	20.6	22.6	23.5	21.9	21.8	22.3	21.5	21.5	-0.37
MEUPCC	END USE DEMAND/ POP (GJ)	240.1	230.3	237.3	238.0	243.6	247.9	256.7	262.3	0.40
MEUPRC	" " / RDP/	18.5	17.8	18.0	17.1	16.2	15.6	15.0	14.6	-0.84
RPDPCC	PRIMARY DEMAND / POP (GJ)	318.3	356.1	336.1	347.8	364.4	375.4	386.4	386.1	0.56
RPDPRC	" " / RDP	24.5	27.5	25.6	24.9	24.3	23.7	22.6	21.5	-0.69

* *Includes non-combustible use.*
Note: 1994 electricity data subject to small adjustments.

Summary Results - Energy Demand (Petajoules)

					Projection					Annual Growth
		1990	1994	1995	2000	2005	2010	2015	2020	1995-2020
	END USE DEMAND BY FUEL:									
MTSEUC	TOTAL END USE DEMAND	1578.3	1652.0	1689.6	1737.1	1811.7	1885.3	1987.4	2083.4	0.84
MRPEUC	RPPs	685.8	695.2	695.3	675.9	694.4	723.0	766.7	807.5	0.60
MNGEUC	NATURAL GAS	211.0	217.2	233.3	268.3	279.6	282.1	293.6	306.1	1.09
MELEUC	ELECTRICITY	528.7	577.0	589.6	603.3	631.8	661.0	696.3	727.7	0.85
MCCEUC	COAL	20.3	17.3	17.8	26.1	28.5	29.2	30.9	32.6	2.45
MLPEUC	LPGs	17.4	21.8	17.8	24.9	29.0	32.5	32.3	32.0	2.37
MKGEUC	COKE AND COKE OVEN GAS	6.5	2.5	2.6	4.3	4.8	4.8	5.1	5.4	2.97
MSTEUC	STEAM	0.1	0.2	0.2	0.3	0.4	0.4	0.4	0.4	2.81
MOFEUC	OTHER	69.7	85.5	97.0	98.4	107.7	117.0	127.5	137.9	1.42
MWDEUC	RESIDENTIAL WOOD	35.9	35.3	35.9	35.8	35.7	35.4	34.8	34.0	-0.22
	END USE DEMAND BY SECTOR:									
MTSEUC	TOTAL END-USE DEMAND	1578.3	1652.0	1689.6	1737.1	1811.7	1885.3	1987.4	2083.4	0.84
MTSRAC	RESIDENTIAL	313.9	320.5	311.7	312.7	302.5	298.2	305.8	313.2	0.02
MTSCPC	COMMERCIAL	189.6	196.4	206.4	207.6	214.1	224.7	238.5	255.9	0.86
MTSINC	INDUSTRIAL *	677.9	715.7	756.1	783.1	839.1	884.0	935.7	979.0	1.04
MTSTRC	TRANSPORTATION	396.8	419.4	415.5	433.6	456.0	478.4	507.4	535.3	1.02
	PRIMARY DEMAND BY SECTOR:									
HTSPDC	TOTAL PRIMARY ENERGY DEMAND	1572.6	1721.7	1763.5	1831.7	1897.5	1940.5	2018.9	2132.3	0.76
MTSEUC	END-USE DEMAND	1578.3	1652.0	1689.6	1737.1	1811.7	1885.3	1987.4	2083.4	0.84
MTSFFC	FOSSIL FUEL PRODUCERS	36.5	41.5	46.0	57.2	57.9	58.7	60.0	61.2	1.15
MTSELC	ELECTRICITY GENERATION	-42.2	27.2	27.8	37.4	27.8	-3.6	-28.4	-12.4	-196.82
	PRIMARY DEMAND BY FUEL									
HTSPDC	TOTAL PRIMARY ENERGY DEMAND	1572.6	1721.7	1763.5	1831.7	1897.5	1940.5	2018.9	2132.3	0.76
HRPPDC	RPPs	705.3	699.2	695.1	682.7	699.1	725.8	767.8	807.1	0.60
HNGPDC	NATURAL GAS	211.5	217.8	235.0	276.5	288.4	291.1	302.9	315.8	1.19
HLPPDC	LPGs	17.4	23.8	19.2	27.0	31.3	35.1	34.9	34.5	2.37
HCCPDC	COAL	27.0	20.0	20.6	30.6	33.6	34.4	36.4	38.4	2.52
HENPDC	NUCLEAR ELECTRICITY	47.9	62.5	56.7	62.9	62.9	62.9	62.9	62.9	0.42
HEHPDC	HYDRO ELECTRICITY (3.6)	457.9	579.5	600.9	609.5	630.4	630.4	643.4	693.1	0.57
HOFPDC	OTHER (RENEWABLES)	105.6	118.9	136.1	142.4	151.8	160.9	170.8	180.5	1.14
	RATIOS:									
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	121.9	115.5	110.4	103.5	94.1	87.2	83.6	80.8	-1.24
MCDPRC	COM. DEMAND / COM. RDP	1.6	1.6	1.6	1.5	1.4	1.4	1.4	1.4	-0.70
RIDPRC	IND. DEMAND / IND. RDP	16.1	17.5	18.1	16.2	15.8	15.2	14.6	13.9	-1.06
MEUPCC	END USE DEMAND/ POP (GJ)	224.8	226.8	230.5	226.4	226.4	226.8	230.5	233.2	0.05
MEUPRC	" " / RDP/	14.0	14.2	14.4	13.2	12.3	11.4	10.7	10.0	-1.43
RPDPCC	PRIMARY DEMAND / POP (GJ)	236.4	230.4	240.6	238.7	237.1	233.5	234.1	238.7	-0.03
RPDPRC	" " / RDP	14.7	14.5	15.0	13.9	12.9	11.7	10.8	10.3	-1.51

* *Includes non combustible use.*

Note: 1994 electricity data subject to small adjustments.

Summary Results - Energy Demand (Petajoules)

Ontario

Code		1990	1994	1995	Projection 2000	2005	2010	2015	2020	Annual Growth 1995-2020
	END USE DEMAND BY FUEL:									
MTSEUC	TOTAL END USE DEMAND	2578.8	2670.8	2733.6	2845.3	2968.2	3105.3	3275.4	3450.5	0.94
MRPEUC	RPPs	1029.5	1061.0	1080.9	1085.5	1134.0	1205.8	1291.0	1373.1	0.96
MNGEUC	NATURAL GAS	770.3	850.4	865.5	966.0	984.2	1000.3	1038.4	1082.1	0.90
MELEUC	ELECTRICITY	473.1	463.0	479.5	482.4	521.7	554.9	594.9	639.2	1.16
MCCEUC	COAL	20.5	16.2	16.7	16.8	17.2	17.7	18.4	19.1	0.54
MLPEUC	LPGs	56.5	68.2	61.1	66.6	75.4	83.2	85.0	86.3	1.39
MKGEUC	COKE AND COKE OVEN GAS	127.6	120.3	124.0	124.7	127.6	130.8	136.1	141.5	0.53
MSTEUC	STEAM	19.1	7.3	7.1	7.2	7.3	7.5	7.8	8.1	0.53
MOFEUC	OTHER	61.6	64.3	77.5	75.1	79.1	83.2	81.9	79.4	0.10
MWDEUC	RESIDENTIAL WOOD	18.8	20.1	21.1	21.2	21.7	22.0	21.9	21.8	0.13
	END USE DEMAND BY SECTOR:									
MTSEUC	TOTAL END-USE DEMAND	2578.8	2670.8	2733.6	2845.3	2968.2	3105.3	3275.4	3450.5	0.94
MTSRAC	RESIDENTIAL	523.5	576.3	569.0	560.1	543.3	533.1	547.6	566.5	-0.02
MTSCPC	COMMERCIAL	315.0	357.7	368.3	383.6	409.3	437.6	470.5	507.9	1.29
MTSINC	INDUSTRIAL *	1098.1	1078.5	1123.8	1196.3	1271.6	1345.2	1410.8	1474.8	1.09
MTSTRC	TRANSPORTATION	642.2	658.4	672.4	705.3	744.1	789.4	846.4	901.4	1.18
	PRIMARY DEMAND BY SECTOR:									
HTSPDC	TOTAL PRIMARY ENERGY DEMAND	3320.3	3641.8	3788.5	3883.1	4048.3	4241.4	4419.0	4607.9	0.79
MTSEUC	END-USE DEMAND	2578.8	2670.8	2733.6	2845.3	2968.2	3105.3	3275.4	3450.5	0.94
MTSFFC	FOSSIL FUEL PRODUCERS	87.6	112.5	125.2	125.8	129.9	134.0	141.1	151.6	0.77
MTSELC	ELECTRICITY GENERATION	653.8	858.1	929.6	912.0	950.2	1002.0	1002.6	1005.7	0.32
	PRIMARY DEMAND BY FUEL									
HTSPDC	TOTAL PRIMARY ENERGY DEMAND	3320.3	3641.8	3788.5	3883.1	4048.3	4241.4	4419.0	4607.9	0.79
HRPPDC	RPPs	1046.7	1065.2	1095.6	1101.3	1147.1	1218.5	1303.3	1385.3	0.94
HNGPDC	NATURAL GAS	824.6	965.3	974.3	1100.2	1126.9	1159.4	1258.9	1414.7	1.50
HLPPDC	LPGs	57.6	68.2	61.1	66.6	75.4	83.2	85.0	86.3	1.39
HCCPDC	COAL	439.2	304.6	320.6	209.4	284.0	400.7	629.9	718.9	3.28
HENPDC	NUCLEAR ELECTRICITY	686.4	1053.1	1077.6	1129.8	1133.7	1093.1	846.4	704.6	-1.69
HEHPDC	HYDRO ELECTRICITY (3.6)	185.5	102.7	137.7	143.1	143.1	143.1	152.5	156.6	0.52
HOFPDC	OTHER (RENEWABLES)	80.4	82.7	120.5	131.5	136.9	142.2	141.7	140.1	0.60
	RATIOS:									
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	147.7	148.0	144.9	134.1	121.8	111.6	105.9	101.7	-1.41
MCDPRC	COM. DEMAND / COM. RDP	1.7	1.8	1.8	1.7	1.6	1.5	1.5	1.5	-0.73
RIDPRC	IND. DEMAND / IND. RDP	13.0	12.3	12.3	10.9	10.3	9.7	9.2	8.6	-1.41
MEUPCC	END USE DEMAND/ POP (GJ)	249.4	244.3	246.2	244.6	243.6	244.0	245.0	244.7	-0.02
MEUPRC	" " / RDP/	12.9	12.8	12.8	11.8	10.9	10.2	9.6	9.1	-1.35
RPDPCC	PRIMARY DEMAND / POP (GJ)	322.5	335.1	341.2	333.8	332.3	333.2	330.5	326.8	-0.17
RPDPRC	" " / RDP	16.6	17.5	17.7	16.0	14.9	14.0	13.0	12.2	-1.50

* *Includes non-combustible use.*
Note: 1994 electricity data subject to small adjustments.

Summary Results - Energy Demand (Petajoules)

Manitoba

Code		1990	1994	1995	2000 (Projection)	2005 (Projection)	2010 (Projection)	2015 (Projection)	2020 (Projection)	Annual Growth 1995-2020
	END USE DEMAND BY FUEL:									
MTSEUC	TOTAL END USE DEMAND	244.8	233.7	248.8	245.7	250.9	260.3	272.6	282.5	0.51
MRPEUC	RPPs	97.7	97.0	103.3	97.0	99.2	104.9	111.1	115.6	0.45
MNGEUC	NATURAL GAS	73.5	68.1	71.9	72.4	72.5	72.3	73.2	73.7	0.10
MELEUC	ELECTRICITY	54.7	56.0	58.8	61.1	63.4	66.3	70.6	74.8	0.97
MCCEUC	COAL	2.1	2.1	2.2	2.3	2.4	2.5	2.7	2.8	0.97
MLPEUC	LPGs	3.7	3.5	4.5	4.3	4.4	4.4	4.5	4.6	0.09
MKGEUC	COKE AND COKE OVEN GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
MSTEUC	STEAM	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
MOFEUC	OTHER	11.5	4.7	5.6	6.0	6.7	7.5	8.1	8.7	1.78
MWDEUC	RESIDENTIAL WOOD	2.4	2.3	2.5	2.5	2.4	2.4	2.3	2.2	-0.51
	END USE DEMAND BY SECTOR:									
MTSEUC	TOTAL END-USE DEMAND	244.8	233.7	248.8	245.7	250.9	260.3	272.6	282.5	0.51
MTSRAC	RESIDENTIAL	67.8	65.2	67.5	62.3	60.1	59.0	60.2	61.5	-0.37
MTSCPC	COMMERCIAL	43.3	43.5	45.8	46.2	47.3	47.4	47.3	46.9	0.09
MTSINC	INDUSTRIAL *	58.8	50.4	56.2	60.4	65.2	71.0	77.5	82.6	1.55
MTSTRC	TRANSPORTATION	74.9	74.7	79.2	76.7	78.3	82.9	87.6	91.4	0.57
	PRIMARY DEMAND BY SECTOR:									
HTSPDC	TOTAL PRIMARY ENERGY DEMAND	272.7	275.7	322.6	318.6	323.2	328.2	345.7	358.7	0.43
MTSEUC	END-USE DEMAND	244.8	233.7	248.8	245.7	250.9	260.3	272.6	282.5	0.51
MTSFPC	FOSSIL FUEL PRODUCERS	22.4	37.2	35.6	41.7	43.8	45.6	47.8	50.8	1.43
MTSELC	ELECTRICITY GENERATION	5.5	4.7	38.2	31.2	28.5	22.3	25.2	25.3	-1.63
	PRIMARY DEMAND BY FUEL									
HTSPDC	TOTAL PRIMARY ENERGY DEMAND	272.7	275.7	322.6	318.6	323.2	328.2	345.7	358.7	0.43
HRPPDC	RPPs	98.2	97.6	103.5	97.0	99.2	105.0	111.2	115.7	0.45
HNGPDC	NATURAL GAS	89.6	91.9	97.4	103.3	105.0	106.2	108.5	116.3	0.71
HLPPDC	LPGs	3.7	3.6	4.6	4.3	4.4	4.4	4.6	4.6	0.00
HCCPDC	COAL	7.1	5.1	4.4	5.1	5.2	2.5	2.7	2.8	-1.79
HENPDC	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
HEHPDC	HYDRO ELECTRICITY (3.6)	67.3	70.3	104.4	100.1	100.1	100.1	108.0	108.0	0.14
HOFPDC	OTHER (RENEWABLES)	6.9	7.3	8.4	8.8	9.4	10.1	10.7	11.2	1.16
	RATIOS:									
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	149.3	138.3	144.1	128.5	117.4	108.8	104.9	102.0	-1.37
MCDPRC	COM. DEMAND / COM. RDP	2.0	1.9	1.9	1.8	1.8	1.6	1.5	1.4	-1.21
RIDPRC	IND. DEMAND / IND. RDP	14.3	13.7	14.4	13.7	13.6	13.1	12.7	12.8	-0.47
MEUPCC	END USE DEMAND/ POP (GJ)	220.8	206.6	218.7	208.8	206.6	208.4	212.4	214.6	-0.07
MEUPRC	" " / RDP/	13.8	13.4	14.0	12.8	12.0	11.2	10.6	10.1	-1.28
RPDPCC	PRIMARY DEMAND / POP (GJ)	241.1	264.3	283.5	270.7	266.1	262.7	269.4	272.5	-0.16
RPDPRC	" " / RDP	15.1	17.1	18.1	16.5	15.4	14.1	13.4	12.8	-1.36

* *Includes non-combustible use.*
Note: 1994 electricity data subject to small adjustments.

Summary Results - Energy Demand (Petajoules)

Saskatchewan

		1990	1994	1995	Projection 2000	2005	2010	2015	2020	Annual Growth 1995-2020
	END USE DEMAND BY FUEL:									
MTSEUC	TOTAL END USE DEMAND	272.6	323.8	329.1	337.3	348.3	358.5	376.7	393.9	0.72
MRPEUC	RPPs	129.7	132.3	132.8	129.9	134.9	142.1	149.6	157.1	0.67
MNGEUC	NATURAL GAS	89.4	133.0	136.3	142.1	144.7	144.4	149.8	155.2	0.52
MELEUC	ELECTRICITY	38.9	44.7	42.9	44.7	46.9	49.3	52.8	55.7	1.05
MCCEUC	COAL	3.6	2.6	2.5	2.7	2.8	2.8	2.9	3.0	0.73
MLPEUC	LPGs	4.6	4.5	4.3	6.7	6.9	6.4	6.7	7.1	2.03
MKGEUC	COKE AND COKE OVEN GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
MSTEUC	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
MOFEUC	OTHER	4.5	5.4	8.9	9.7	10.8	12.1	13.5	14.4	1.94
MWDEUC	RESIDENTIAL WOOD	1.9	1.3	1.4	1.4	1.4	1.4	1.3	1.3	-0.30
	END USE DEMAND BY SECTOR:									
MTSEUC	TOTAL END-USE DEMAND	272.6	323.8	329.1	337.3	348.3	358.5	376.7	393.9	0.72
MTSRAC	RESIDENTIAL	85.3	90.6	90.6	88.8	89.5	86.2	87.1	88.8	-0.08
MTSCPC	COMMERCIAL	35.7	41.8	41.2	41.4	42.2	43.1	44.5	44.6	0.32
MTSINC	INDUSTRIAL *	71.4	105.8	110.0	119.0	125.4	133.4	144.4	154.5	1.37
MTSTRC	TRANSPORTATION	77.9	85.6	87.3	88.0	91.3	95.8	100.8	105.9	0.78
	PRIMARY DEMAND BY SECTOR:									
HTSPDC	TOTAL PRIMARY ENERGY DEMAND	457.8	565.5	579.1	623.1	640.8	653.9	683.6	709.1	0.81
MTSEUC	END-USE DEMAND	272.6	323.8	329.1	337.3	348.3	358.5	376.7	393.9	0.72
MTSFFC	FOSSIL FUEL PRODUCERS	102.0	141.8	151.4	180.7	184.6	185.8	193.2	202.6	1.17
MTSELC	ELECTRICITY GENERATION	83.1	100.0	98.6	105.1	107.9	109.5	113.7	112.6	0.53
	PRIMARY DEMAND BY FUEL									
HTSPDC	TOTAL PRIMARY ENERGY DEMAND	457.8	565.5	579.1	623.1	640.8	653.9	683.6	709.1	0.81
HRPPDC	RPPs	126.9	135.3	134.7	131.2	136.1	143.4	151.0	158.6	0.66
HNGPDC	NATURAL GAS	186.5	259.3	273.7	315.2	321.3	325.0	332.8	346.3	0.95
HLPPDC	LPGs	4.9	5.4	5.2	8.2	8.4	7.8	8.2	8.7	2.08
HCCPDC	COAL	115.5	143.6	138.9	141.8	146.0	147.2	159.6	162.5	0.63
HENPDC	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
HEHPDC	HYDRO ELECTRICITY (3.6)	15.1	12.4	14.8	13.1	13.1	13.1	13.1	13.1	-0.49
HOFPDC	OTHER (RENEWABLES)	8.8	9.5	11.7	13.6	15.8	17.4	18.8	19.9	2.15
	RATIOS:									
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	172.7	173.7	174.2	163.1	154.7	136.8	129.2	124.8	-1.33
MCDPRC	COM. DEMAND / COM. RDP	1.6	1.9	1.8	1.8	1.6	1.6	1.5	1.4	-1.09
RIDPRC	IND. DEMAND / IND. RDP	18.2	28.5	29.1	28.1	28.0	27.9	27.9	27.7	-0.19
MEUPCC	END USE DEMAND/ POP (GJ)	267.4	319.4	323.8	323.8	322.9	321.8	328.5	334.8	0.13
MEUPRC	" " / RDP/	15.6	17.6	17.6	16.7	16.0	15.1	14.4	13.7	-1.00
RPDPCC	PRIMARY DEMAND / POP (GJ)	443.0	539.2	569.8	598.1	594.1	586.9	596.1	602.7	0.22
RPDPRC	" " / RDP	25.9	29.7	31.0	30.8	29.3	27.5	26.1	24.7	-0.91

* *Includes non-combustible use.*
Note: 1994 electricity data subject to small adjustments.

Summary Results - Energy Demand (Petajoules)

Alberta

		1990	1994	1995	2000 (Projection)	2005 (Projection)	2010 (Projection)	2015 (Projection)	2020 (Projection)	Annual Growth 1995-2020
	END USE DEMAND BY FUEL:									
MTSEUC	TOTAL END USE DEMAND	1160.0	1301.7	1338.6	1442.9	1523.7	1584.9	1649.7	1717.7	1.00
MRPEUC	RPPs	380.5	397.6	406.3	417.9	444.5	470.9	500.6	528.8	1.06
MNGEUC	NATURAL GAS	536.7	561.4	596.7	618.5	658.1	662.5	681.1	704.2	0.66
MELEUC	ELECTRICITY	100.1	116.6	113.9	113.0	117.6	124.1	132.1	139.3	0.81
MCCEUC	COAL	0.9	0.8	1.0	0.9	1.5	1.7	1.6	1.4	1.35
MLPEUC	LPGs	126.0	181.7	160.2	224.8	226.4	242.6	242.9	243.6	1.69
MKGEUC	COKE AND COKE OVEN GAS	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	
MSTEUC	STEAM	0.2	4.5	6.1	10.1	10.9	11.5	11.5	11.9	2.71
MOFEUC	OTHER	17.2	38.5	53.7	57.0	64.0	71.0	79.1	87.9	1.99
MWDEUC	RESIDENTIAL WOOD	1.0	0.6	0.7	0.6	0.6	0.6	0.6	0.6	-0.61
	END USE DEMAND BY SECTOR:									
MTSEUC	TOTAL END-USE DEMAND	1160.0	1301.7	1338.6	1442.9	1523.7	1584.9	1649.7	1717.7	1.00
MTSRAC	RESIDENTIAL	184.9	200.9	206.9	200.1	199.3	185.1	182.5	183.9	-0.47
MTSCPC	COMMERCIAL	141.3	148.0	159.0	148.6	147.0	146.7	147.3	147.4	-0.30
MTSINC	INDUSTRIAL *	572.1	688.1	704.4	811.4	873.2	929.8	975.2	1021.5	1.50
MTSTRC	TRANSPORTATION	261.7	264.6	268.3	282.9	304.2	323.3	344.7	365.0	1.24
	PRIMARY DEMAND BY SECTOR:									
HTSPDC	TOTAL PRIMARY ENERGY DEMAND	2067.8	2391.7	2500.4	2605.8	2702.9	2773.0	2846.1	2939.1	0.65
MTSEUC	END-USE DEMAND	1160.0	1301.7	1338.6	1442.9	1523.7	1584.9	1649.7	1717.7	1.00
MTSFFC	FOSSIL FUEL PRODUCERS	603.7	720.2	801.0	797.1	818.8	823.2	834.0	856.4	0.27
MTSELC	ELECTRICITY GENERATION	304.1	369.6	360.9	365.8	360.3	364.9	362.4	365.0	0.05
	PRIMARY DEMAND BY FUEL									
HTSPDC	TOTAL PRIMARY ENERGY DEMAND	2067.8	2391.7	2500.4	2605.8	2702.9	2773.0	2846.1	2939.1	0.65
HRPPDC	RPPs	414.9	440.8	453.1	459.3	484.6	510.5	537.7	564.9	0.89
HNGPDC	NATURAL GAS	1098.2	1233.8	1334.1	1382.4	1462.0	1481.8	1530.6	1564.8	0.64
HLPPDC	LPGs	127.0	182.1	160.5	225.3	226.9	243.1	243.4	244.1	1.69
HCCPDC	COAL	397.5	486.0	482.5	463.5	445.9	446.1	433.6	454.5	-0.24
HENPDC	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
HEHPDC	HYDRO ELECTRICITY (3.6)	7.4	6.5	8.0	6.6	6.6	6.6	6.6	6.6	-0.77
HOFPDC	OTHER (RENEWABLES)	22.8	42.5	62.1	68.6	76.6	84.7	93.9	104.0	2.08
	RATIOS:									
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	189.5	193.3	193.3	176.2	164.4	141.3	128.9	121.3	-1.85
MCDPRC	COM. DEMAND / COM. RDP	2.1	2.0	2.1	1.8	1.7	1.5	1.4	1.3	-1.85
RIDPRC	IND. DEMAND / IND. RDP	17.5	16.6	18.7	17.9	17.6	17.3	17.6	17.5	-0.26
MEUPCC	END USE DEMAND/ POP (GJ)	453.8	478.7	487.1	499.9	504.7	503.6	502.5	501.1	0.11
MEUPRC	" " / RDP/	18.7	18.4	18.5	18.1	17.4	16.5	15.8	15.1	-0.80
RPDPCC	PRIMARY DEMAND / POP (GJ)	811.8	875.5	909.8	902.8	895.2	881.2	866.9	857.4	-0.24
RPDPRC	" " / RDP	33.5	33.6	34.5	32.7	30.9	28.9	27.3	25.8	-1.15

* *Includes non-combustible use.*

Note 1994 electricity data subject to small adjustments.

Annex C

Summary Results - Energy Demand (Petajoules) B. C. + Yk. + N. W. T.

		1990	1994	1995	Projection 2000	2005	2010	2015	2020	Annual Growth 1995-2020
	END USE DEMAND BY FUEL:									
MTSEUC	TOTAL END USE DEMAND	940.1	1026.7	1055.0	1141.8	1218.2	1277.2	1366.3	1455.1	1.29
MRPEUC	RPPs	367.7	375.4	389.7	406.5	429.6	447.0	473.8	501.5	1.01
MNGEUC	NATURAL GAS	209.8	234.6	242.5	261.1	271.3	268.0	273.9	279.3	0.57
MELEUC	ELECTRICITY	179.2	191.4	193.5	207.7	220.4	236.0	256.4	275.7	1.43
MCCEUC	COAL	3.3	5.9	6.0	10.6	11.8	11.6	12.0	12.5	2.98
MLPEUC	LPGs	14.1	20.8	17.9	25.0	25.3	26.3	28.2	30.2	2.11
MKGEUC	COKE AND COKE OVEN GAS	0.8	1.7	1.8	3.1	3.5	3.4	3.5	3.7	2.92
MSTEUC	STEAM	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	
MOFEUC	OTHER	157.4	190.8	197.9	221.5	250.1	278.8	312.3	346.2	2.26
MWDEUC	RESIDENTIAL WOOD	7.1	6.1	5.8	6.3	6.2	6.2	6.1	5.9	0.07
	END USE DEMAND BY SECTOR:									
MTSEUC	TOTAL END-USE DEMAND	940.1	1026.7	1055.0	1141.8	1218.2	1277.2	1366.3	1455.1	1.29
MTSRAC	RESIDENTIAL	138.5	152.0	150.7	164.7	164.9	155.3	155.9	158.6	0.20
MTSCPC	COMMERCIAL	108.2	120.7	124.1	130.2	138.2	148.3	158.5	167.7	1.21
MTSINC	INDUSTRIAL *	436.1	455.4	461.6	502.5	551.5	599.4	658.4	714.0	1.76
MTSTRC	TRANSPORTATION	257.3	298.6	318.7	344.3	363.7	374.2	393.4	414.7	1.06
	PRIMARY DEMAND BY SECTOR:									
HTSPDC	TOTAL PRIMARY ENERGY DEMAND	1051.6	1180.2	1206.9	1324.6	1421.5	1487.7	1570.0	1657.0	1.28
MTSEUC	END-USE DEMAND	940.1	1026.7	1055.0	1141.8	1218.2	1277.2	1366.3	1455.1	1.29
MTSFPC	FOSSIL FUEL PRODUCERS	102.4	101.4	107.3	115.9	124.3	128.9	134.5	139.9	1.07
MTSELC	ELECTRICITY GENERATION	9.0	51.7	44.6	66.8	79.0	81.7	69.2	62.1	1.33
	PRIMARY DEMAND BY FUEL									
HTSPDC	TOTAL PRIMARY ENERGY DEMAND	1051.6	1180.2	1206.9	1324.6	1421.5	1487.7	1570.0	1657.0	1.28
HRPPDC	RPPs	388.2	393.7	415.9	423.5	448.3	468.1	497.3	527.2	0.95
HNGPDC	NATURAL GAS	283.3	337.5	356.1	379.0	413.8	427.2	438.7	447.2	0.92
HLPPDC	LPGs	14.1	20.7	17.9	25.0	25.3	26.4	28.3	30.3	2.13
HCCPDC	COAL	8.2	11.4	13.0	23.1	25.7	25.1	26.0	27.1	2.98
HENPDC	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
HEHPDC	HYDRO ELECTRICITY (3.6)	193.3	221.9	181.3	219.6	221.8	221.8	222.7	229.6	0.95
HOFPDC	OTHER (RENEWABLES)	164.5	194.9	222.7	254.4	286.6	319.2	357.0	395.5	2.32
	RATIOS:									
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	112.6	109.3	104.2	103.1	95.4	83.2	76.6	71.8	-1.47
MCDPRC	COM. DEMAND / COM. RDP	1.7	1.6	1.6	1.5	1.4	1.3	1.3	1.2	-1.01
RIDPRC	IND. DEMAND / IND. RDP	26.2	26.6	26.9	26.5	26.4	25.9	25.6	25.4	-0.24
MEUPCC	END USE DEMAND/ POP (GJ)	277.5	272.9	273.3	274.5	277.1	276.6	280.5	281.9	0.12
MEUPRC	" " / RDP/	15.3	15.0	15.1	14.8	14.2	13.3	12.7	12.2	-0.86
RPDPCC	PRIMARY DEMAND / POP (GJ)	311.4	311.5	312.7	318.5	323.3	322.2	322.3	321.1	0.11
RPDPRC	" " / RDP	17.1	17.1	17.3	17.1	16.5	15.5	14.6	13.8	-0.88

* *Includes non-combustible use.*
Note: 1994 electricity data subject to small adjustments.

End-Use Demand by Major Fuels (Petajoules)

		1990	1994	1995	Projection 2000	2005	2010	2015	2020	Annual Growth 1995-2020
	RESIDENTIAL:									
MTSRAC	TOTAL RESIDENTIAL	1429.9	1520.1	1511.5	1505.1	1474.9	1430.3	1453.1	1487.3	-0.06
HDFAGC	DIESEL FUEL AGRICULTURE	71.4	84.5	89.0	88.7	91.7	95.5	100.0	104.8	0.66
HTSORC	TOTAL OTHER RESIDENTIAL	1358.5	1435.6	1422.5	1416.3	1383.2	1334.8	1353.1	1382.5	-0.11
HELRAC	ELECTRICITY	503.0	505.4	507.4	518.9	521.6	532.8	559.8	591.4	0.61
HNGRAC	NATURAL GAS	551.6	655.7	653.1	667.5	642.9	583.2	566.7	559.5	-0.62
HRPORC	TOTAL RPPs	197.7	176.2	154.1	119.4	101.4	93.8	105.1	114.9	-1.17
HCCRAC	COAL	2.5	1.5	1.7	1.6	2.3	2.5	2.6	2.5	1.55
HLPRAC	LPG'S	19.6	14.7	15.4	12.9	18.3	25.1	22.0	18.2	0.67
HWDRAC	WOOD	84.1	82.0	90.9	96.0	96.8	97.3	96.9	96.1	0.22
	COMMERCIAL:									
MTSCPC	TOTAL COMMERCIAL	892.7	965.9	1005.6	1019.8	1061.1	1112.6	1173.0	1238.0	0.84
HELCPC	ELECTRICITY	382.2	408.8	422.2	416.4	437.6	467.1	501.7	537.3	0.97
HNGCPC	NATURAL GAS	387.8	421.3	433.0	459.6	472.8	486.3	504.9	527.5	0.79
MRPCPC	TOTAL RPPs	101.1	85.8	94.6	89.3	92.6	97.1	100.8	104.3	0.39
HLPCPC	LPGs	21.3	50.0	55.7	54.4	58.1	62.1	65.7	68.8	0.85
	INDUSTRIAL:									
MTSINC	TOTAL INDUSTRIAL	3122.2	3294.6	3424.7	3690.5	3967.1	4220.3	4480.1	4716.1	1.29
MELINC	ELECTRICITY	595.2	644.9	662.7	691.1	764.1	819.1	877.2	921.5	1.33
MNGINC	NATURAL GAS	948.7	985.3	1052.2	1194.0	1287.0	1351.9	1430.0	1504.8	1.44
MRPINC	TOTAL RPPs	836.6	833.4	857.8	811.1	850.8	906.1	959.8	1007.3	0.64
MCCINC	COAL	50.0	44.7	46.1	59.5	63.9	64.9	68.1	71.5	1.77
MLPINC	LPGs	163.0	206.7	165.8	255.4	259.5	275.1	276.9	279.5	2.11
MSTINC	STEAM	20.8	14.6	16.6	21.4	23.1	23.8	24.7	26.1	1.83
MKGCINC	COKE & COKE OVEN GAS	139.9	129.0	132.9	137.5	142.3	145.6	152.0	158.9	0.72
HHPINC	PULP SPENTING & WOOD WASTE	367.9	436.0	490.6	520.6	576.4	633.9	691.5	746.8	1.69
	TRANSPORTATION:									
MTSTRC	TOTAL TRANSPORTATION	1895.4	1983.2	2024.9	2122.9	2236.6	2353.2	2503.8	2651.7	1.08
MRPTRC	TOTAL RPPs	1863.7	1940.8	1979.8	2075	2186.1	2300.3	2448.1	2593.3	1.09
HELTRC	ELECTRICITY	3.1	3	3	3	3	3	3	3	0.00
MNLTRC	NATURAL GAS & LPGs	28.6	39.1	40.9	43.1	45.7	48	50.7	53.4	1.07
HOFTRC	OTHER FUELS	0	0.8	1.2	1.8	1.9	1.9	2	2	2.06

Industrial Demand by Industry I (Petajoules)

					Projection					Annual Growth
		1990	1994	1995	2000	2005	2010	2015	2020	1995-2020
	PULP AND PAPER MILLS:									
HTSPPC	TOTAL	743.8	830.6	881.0	902.0	972.0	1047.8	1134.1	1207.5	1.27
HRPPPC	REFINED PETROLEUM PRODUCTS	92.9	67.1	64.2	46.4	45.7	49.2	53.1	56.0	-0.55
HELPPC	ELECTRICITY	175.7	191.6	189.7	184.5	195.8	207.6	223.4	232.0	0.81
HNGPPC	NATURAL GAS	101.7	130.2	128.1	135.2	139.7	143.2	151.0	156.0	0.79
HOFPPC	OTHER FUELS	5.6	5.7	8.4	15.3	14.4	13.9	15.1	16.7	2.79
HHGINC	WOOD WASTE	98.8	125.4	141.5	149.9	165.8	182.4	199.1	215.0	1.69
HPLINC	PULP & SPENT PULPING LIQUOR	269.1	310.6	349.1	370.7	410.6	451.5	492.4	531.8	1.70
	CHEMICAL:									
HTSCHC	TOTAL	237.5	242.5	270.5	294.0	319.2	353.9	398.0	439.2	1.96
HRPCHC	REFINED PETROLEUM PRODUCTS	9.2	12.5	12.5	9.5	9.9	11.9	14.0	16.0	0.99
HELCHC	ELECTRICITY	65.3	61.3	66.5	68.6	76.5	85.9	97.2	107.6	1.94
HNGCHC	NATURAL GAS	144.1	161.6	183.7	204.7	219.1	238.5	265.1	290.3	1.85
HOFCHC	OTHER FUELS	18.8	7.0	7.8	11.2	13.8	17.5	21.6	25.4	4.84
	IRON AND STEEL:									
HTSISC	TOTAL	219.3	234.1	237.5	239.9	244.5	247.2	250.7	253.6	0.26
HRPISC	REFINED PETROLEUM PRODUCTS	15.1	10.5	10.1	7.5	7.1	7.7	8.2	8.5	-0.69
HELISC	ELECTRICITY	28.5	31.3	32.9	39.6	42.1	42.8	43.2	43.8	1.15
HNGISC	NATURAL GAS	54.7	75.4	76.6	81.1	81.5	81.4	82.2	82.8	0.31
HOFISC	OTHER FUELS	120.9	117.1	117.9	111.7	113.8	115.2	117.1	118.6	0.02
	SMELTING AND REFINING:									
HTSSRC	TOTAL	183.0	215.3	217.6	225.4	254.1	272.2	288.9	302.6	1.33
HRPSRC	REFINED PETROLEUM PRODUCTS	14.4	10.1	10.7	10.2	12.5	14.6	16.3	17.9	2.08
HELSRC	ELECTRICITY	129.5	167.3	167.8	173.4	195.4	210.1	222.9	232.5	1.31
HNGSRC	NATURAL GAS	24.8	26.0	28.2	31.4	35.6	38.6	41.7	44.7	1.86
HOFSRC	OTHER FUELS	14.3	11.9	10.8	10.4	10.6	8.9	8.0	7.5	-1.45
	MINING:									
MTSMIC	TOTAL	96.6	121.7	133.7	160.6	180.3	182.8	190.9	198.1	1.59
MRPMIC	REFINED PETROLEUM PRODUCTS	29.7	34.2	34.0	29.4	34.5	36.1	38.7	41.1	0.76
MELMIC	ELECTRICITY	47.8	39.1	40.6	40.9	48.0	50.6	54.6	56.8	1.35
MNGMIC	NATURAL GAS	10.5	30.0	32.8	32.2	32.7	32.8	34.7	36.6	0.44
HOFMIC	OTHER FUELS	8.7	18.3	26.3	58.2	65.2	63.3	62.9	63.7	3.60
	OTHER MANUFACTURING:									
HTSOMC	TOTAL	561.7	497.9	544.8	640.3	692.2	736.3	776.3	814.0	1.62
HRPOMC	REFINED PETROLEUM PRODUCTS	35.2	44.1	45.4	38.5	39.1	42.9	46.3	49.0	0.31
HELOMC	ELECTRICITY	121.3	126.4	137.2	157.8	177.1	190.2	200.9	210.8	1.73
HNGOMC	NATURAL GAS	381.6	305.5	343.7	432.8	465.0	488.8	511.7	534.4	1.78
HOFOMC	OTHER FUELS	23.5	21.9	18.5	11.2	10.9	14.4	17.4	19.7	0.25
	CONSTRUCTION:									
HTSCOC	TOTAL	44.4	35.1	33.5	38.0	41.0	44.1	47.3	50.2	1.63
HRPCOC	REFINED PETROLEUM PRODUCTS	41.4	33.3	29.1	22.2	23.3	26.9	30.3	32.9	0.49
HOFCOC	OTHER FUELS	3.0	1.8	4.5	15.8	17.7	17.2	17.0	17.3	5.53

Industrial Demand by Industry II (Petajoules)

		1990	1994	1995	2000 (Projection)	2005 (Projection)	2010 (Projection)	2015 (Projection)	2020 (Projection)	Annual Growth 1995-2020
	FORESTRY:									
HTSFOC	TOTAL	15.7	10.9	11.1	11.0	11.7	12.3	12.9	13.3	0.73
HRPFOC	REFINED PETROLEUM PRODUCTS	15.7	10.9	11.1	11.0	11.7	12.3	12.9	13.3	0.73
	CEMENT:									
HTSCMC	TOTAL	58.2	49.0	50.8	52.6	56.3	59.2	63.3	70.7	1.33
HRPCMC	REFINED PETROLEUM PRODUCTS	10.3	6.6	6.3	4.4	4.3	4.8	5.4	6.2	-0.06
HELCMC	ELECTRICITY	6.8	6.5	6.7	6.6	7.2	7.7	8.4	9.4	1.36
HNGCMC	NATURAL GAS	16.3	12.1	13.0	14.7	15.8	16.3	16.2	17.9	1.29
HOFCMC	OTHER FUELS	24.7	23.8	24.8	26.9	28.9	30.4	33.3	37.2	1.64
	PETROLEUM REFINING:									
HTSPRC	TOTAL	323.8	310.3	315.3	301.6	319.5	336.9	353.2	367.2	0.61
HRPPRC	REFINED PETROLEUM PRODUCTS	66.8	64.8	61.4	43.6	44.1	48.6	52.9	56.7	-0.32
HELPRC	ELECTRICITY	20.3	21.4	21.4	19.8	21.5	23.0	24.4	25.4	0.69
HNGPRC	NATURAL GAS	66.0	54.0	57.0	58.0	60.1	62.2	64.2	66.0	0.59
HOFPRC	OTHER FUELS	170.6	170.1	175.6	180.2	193.8	203.1	211.7	219.1	0.89
	NON COMBUSTION:									
HTSNEC	TOTAL	638.3	744.9	728.9	826.3	876.1	927.6	964.5	999.7	1.27
HRPNEC	REFINED PETROLEUM PRODUCTS	335.2	369.1	397.4	409.5	425.1	448.9	472.2	493.9	0.87
HLPNEC	LIQUID PETROLEUM GASES LPG'S.	139.2	178.1	132.8	202.8	202.8	217.5	217.5	217.5	1.99
HNGNEC	NATURAL GAS	148.9	188.2	189.2	203.8	237.5	250.0	263.2	276.1	1.52
HKGNEC	OTHER FUELS	15.0	9.4	9.6	10.2	10.7	11.2	11.6	12.2	0.96
	TOTAL INDUSTRIAL:									
MTSINC	TOTAL	3122.2	3294.6	3424.7	3690.5	3967.1	4220.3	4480.0	4716.2	1.29
MRPINC	REFINED PETROLEUM PRODUCTS	836.6	833.4	857.8	811.1	850.8	906.1	959.8	1007.3	0.64
MELINC	ELECTRICITY	595.2	644.9	662.7	691.1	763.7	818.0	875.0	918.3	1.31
MNGINC	NATURAL GAS	948.7	985.3	1052.2	1194.0	1287.0	1351.9	1430.0	1504.8	1.44
MOFINC	OTHER FUELS	741.6	831.0	851.9	994.2	1065.6	1144.3	1215.2	1285.8	1.66

Annex C

Transportation Demand (Petajoules)

Canada

		1990	1994	1995	2000 (Projection)	2005 (Projection)	2010 (Projection)	2015 (Projection)	2020 (Projection)	Annual Growth 1995-2020
	PASSENGER CARS:									
NPVSTC	SALES - CARS ('000)	885.0	749.0	672.0	733.0	810.0	888.0	976.0	1065.0	1.86
ENPVS	NEW CAR EFFICIENCY (L/100KM)	9.8	9.6	9.7	9.6	9.4	9.0	8.6	8.3	-0.62
EKTPVC	CAR STOCK EFFICIENCY (L/100KM)	10.6	10.0	10.0	9.7	9.4	9.1	8.7	8.4	-0.69
KTPVSC	CAR STOCK (ALL FUELS) ('000)	10468.0	11135.0	11349.0	11436.0	11849.0	12249.0	13085.0	13964.0	0.83
KMDPCC	AVERAGE-KM TRAVELLED PER CAR	20631.0	21576.0	21579.0	21721.0	21873.0	21977.0	22226.0	22509.0	0.17
KTPVHC	PASSENGER CARS/HOUSEHOLD	1.09	1.07	1.08	1.02	0.99	0.96	0.96	0.96	-0.47
	TRUCKS:									
NTKSTC	SALES - GASOLINE TRUCKS ('000)	398.0	449.0	452.0	512.0	570.0	657.0	723.0	795.0	2.28
ENTKS	NEW GASOLINE TRUCK EFF. (L/100KM)	13.3	13.5	13.4	13.3	13.2	12.7	12.3	12.0	-0.45
KTTKSC	STOCK GASOLINE TRUCKS ('000)	3797.0	4200.0	4231.0	4759.0	5415.0	6158.0	6952.0	7703.0	2.43
KMDTKC	AVERAGE-KM GASOLINE TRUCKS	22389.0	21382.0	21229.0	21061.0	21101.0	21095.0	21198.0	21364.0	0.03
NHYDSC	SALES - HEAVY DIESEL TKS('000)	14.7	24.0	23.9	18.5	21.5	24.3	26.8	29.7	0.88
ENHYS	NEW HVY DIESEL TKS EFF. (L/100KM)	41.3	41.3	41.2	40.0	39.4	38.8	37.9	37.0	-0.43
KTHYSC	STOCK HEAVY DIESEL TRUCKS('000)	190.0	190.0	210.0	216.0	231.0	257.0	286.0	315.0	1.64
KMDHYC	AVERAGE-KM HEAVY DIESEL TRUCKS	78342.0	92670.0	95179.0	102069.0	101255.0	100279.0	100173.0	100074.0	0.20
	ROAD TRANSPORTATION:									
MMGRFC	MOTOR GASOLINE	1176.5	1211.3	1215.0	1248.1	1315.0	1376.6	1462.0	1545.2	0.97
HELRTC	ELECTRICTIY	3.1	3.0	3.0	3.0	3.0	3.0	3.0	3.0	0.00
HDFRTC	DIESEL FUEL	305.3	361.9	397.7	426.3	444.9	477.5	514.6	549.5	1.30
HLPRTC	PROPANE	25.9	33.4	33.1	34.7	36.9	38.8	41.2	43.5	1.10
HNGRTC	COMPRESSED NATURAL GAS	2.6	5.3	7.8	8.4	8.8	9.2	9.6	9.9	0.96
HOFRTC	OTHER FUELS	0.0	0.8	1.2	1.8	1.9	1.9	2.0	2.0	2.06
MTSRTC	TOTAL	1513.4	1615.6	1657.7	1722.3	1810.4	1907.0	2032.2	2153.1	1.05
	RAIL TRANSPORTATION:									
HDFRLC	DIESEL FUEL OIL	89.5	89.3	80.8	90.0	95.2	99.7	105.4	112.0	1.31
	AVIATION TRANSPORTATION:									
MTFAVC	AVIATION TURBO FUEL	179.7	168.7	180.7	199.6	213.2	224.1	237.1	249.7	1.30
MAGAVC	AVIATION GASOLINE	5.5	3.7	4.1	5.3	5.7	6.0	6.4	6.8	2.04
MTSAVC	TOTAL	185.2	172.5	184.8	204.9	218.9	230.2	243.6	256.5	1.32
	MARINE TRANSPORTATION:									
HHFMAC	HEAVY FUEL OIL	60.1	59.9	55.8	57.6	61.4	64.2	67.6	71.0	0.97
HDFMAC	DIESEL FUEL OIL	47.2	44.0	44.9	47.1	49.7	51.1	53.9	57.9	1.02
HMGMAC	GASOLINE	0.0	1.3	0.9	1.0	1.0	1.0	1.1	1.2	1.16
HTSMAC	TOTAL	107.3	105.8	101.6	105.6	112.1	116.4	122.6	130.1	0.99
MTSTRC	TOTAL TRANSPORTATION	1895.4	1983.2	2024.9	2122.9	2236.6	2353.2	2503.8	2651.7	1.08
TOTMGC	TOTAL MOTOR GASOLINE	1176.5	1212.6	1215.9	1249.1	1316.0	1377.6	1463.1	1546.4	0.97
HDFTRC	TOTAL DIESEL	441.9	495.3	523.3	563.4	589.8	628.3	673.8	719.4	1.28

Fossil Fuel Production Demand (Petajoules)

Canada

		1990	1994	1995	Projection 2000	2005	2010	2015	2020	Annual Growth 1995-2020
	FOSSIL FUEL PRODUCTION									
MRPFFC	REFINED PETROLEUM PRODUCTS	47.8	57.1	68.4	69.5	65.6	62.1	56.3	47.8	-1.42
HRPPCC	PRODUCER CONSUMPTION	234.0	230.8	237.6	237.8	250.1	264.6	281.5	291.9	0.83
HDFPLC	PIPELINE DIESEL FUEL	0.6	1.1	1.4	1.4	1.5	1.5	1.6	1.8	1.01
MRPMFC	USED IN MINING (TAR SANDS)	50.6	60.0	66.4	53.1	55.5	57.7	58.9	60.8	-0.35
	MINUS PETROLUEM REFINING IND.									
HRPPRC	RPPs	66.8	64.8	61.4	43.3	44.5	50.1	56.2	61.7	0.02
HOFPRC	STILL GAS	170.6	170.1	175.6	179.6	197.0	211.7	229.5	245.0	1.34
MNGFFC	NATURAL GAS	718.1	881.1	975.8	1028.0	1061.0	1068.1	1095.2	1136.6	0.61
HNGPCC	PRODUCER CONSUMPTION	530.0	589.8	648.0	669.6	685.8	682.6	697.2	718.7	0.42
HNGPLC	PIPELINE USE	133.1	212.0	232.9	262.2	277.2	287.8	300.7	318.9	1.27
MNGMFC	USED IN MINING (TAR SANDS)	55.0	79.4	94.9	96.3	97.9	97.8	97.4	98.9	0.17
MELFFC	ELECTRICITY	198.3	222.1	225.1	226.3	240.8	253.3	265.9	278.0	0.85
HELPCC	PRODUCER CONSUMPTION	130.1	143.9	136.8	139.7	147.9	156.0	166.0	175.2	0.99
HELPLC	PIPELINE USE	8.7	10.3	11.0	12.3	12.9	13.5	14.0	14.8	1.19
MELMFC	USED IN MINING (TAR SANDS)	59.4	67.9	77.3	74.4	80.0	83.8	85.9	88.0	0.52
MLPFFC	LIQUID PETROLEUM GASES	2.4	3.5	2.7	4.1	4.4	4.6	4.7	4.8	2.33
MCCFFC	COAL	4.4	3.9	5.3	9.3	10.3	10.1	10.4	10.9	2.93
MTSFFC	TOTAL	970.9	1167.7	1277.3	1337.3	1382.2	1398.2	1432.6	1478.1	0.59

Annex C Electricity Generation Demand (Petajoules) Canada

		1990	1994	1995	2000	2005	2010	2015	2020	Annual Growth 1995-2020
					Projection					
HTSCRC	TOTAL DEMAND	3115.0	3589.0	3697.0	3785.0	3970.0	4131.0	4252.0	4394.0	0.69
	ELECTRICAL GENERATION:									
	UTILITIES: (TOTAL)									
HTSUEC	TOTAL	2811.2	3437.1	3286.1	3282.7	3402.7	3531.4	3632.3	3751.4	0.53
HCCUEC	COAL	874.3	897.1	923.9	793.6	857.1	972.8	1199.9	1360.7	1.56
HHFUEC	HEAVY FUEL OIL	137.4	64.0	56.1	34.4	51.2	75.4	92.4	20.3	-3.98
HDFUEC	DIESEL FUEL OIL	9.2	9.2	13.6	14.2	24.0	26.1	27.9	44.8	4.88
HLFUEC	LIGHT FUEL OIL	0.9	0.3	0.7	0.8	0.9	1.3	2.2	2.6	5.39
HNGUEC	NATURAL GAS	50.7	114.7	68.2	76.6	82.0	108.8	178.2	272.4	5.70
HENUEC	NUCLEAR	796.0	1176.2	1151.7	1247.7	1251.7	1211.1	964.3	822.5	-1.34
HEHLUC	HYDRO	942.7	1175.7	1071.5	1115.2	1135.6	1135.7	1167.0	1227.8	0.55
HOFUEC	OTHER FUELS	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.00
	INDUSTRY:									
HTSIEC	TOTAL	154.3	156.5	253.9	333.1	391.0	418.9	431.1	445.5	2.27
HCCIEC	COAL	0.6	1.0	0.0	0.0	0.0	0.0	0.0	0.0	
HHFIEC	HEAVY FUEL OIL	7.0	5.9	9.9	6.3	6.3	6.3	6.3	6.3	-1.79
HLFIEC	LIGHT FUEL OIL	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
HDFIEC	DIESEL FUEL OIL	1.6	0.1	1.3	1.3	1.3	1.3	1.3	1.3	0.00
HNGIEC	NATURAL GAS	33.3	34.8	65.8	103.7	142.9	161.9	166.4	172.3	3.93
HEHLIC	HYDRO	111.5	114.7	119.0	126.5	128.9	128.9	128.9	128.9	0.32
HOFIEC	OTHER FUELS	0.0	0.0	57.8	95.3	111.7	120.5	128.2	136.7	3.50
	STEAM GENERATION:									
HTSSTC	TOTAL	5.7	12.6	16.9	23.3	25.1	26.0	26.7	27.9	2.03
HCCSTC	COAL	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
HHFSTC	HEAVY FUEL OIL	3.1	2.0	2.0	2.3	2.8	2.8	3.1	3.5	2.26
HNGSTC	NATURAL GAS	2.1	10.7	14.6	20.4	21.7	22.6	22.9	23.7	1.96
HOFSTC	OTHER FUELS	0.0	0.0	0.3	0.5	0.6	0.6	0.6	0.7	3.45
HCCKGC	COAL FOR COKE & COKE OVEN GAS	145.1	137.3	141.5	146.4	151.5	155.0	161.8	169.1	0.72

Note: 1994 data subject to small adjustments.

Annex C Summary Results by Fuel and by Sector — Canada

		1990	1994	1995	Projection 2000	2005	2010	2015	2020	Annual Growth 1995-2020
	REFINED PETROLEUM PRODUCTS									
HRPPDC	PRIMARY DEMAND	3277.9	3259.1	3324.7	3310.9	3473.1	3666.5	3901.8	4049.5	0.79
MRPEUC	END-USE DEMAND	3071.9	3120.6	3175.3	3183.5	3322.5	3492.8	3713.8	3924.6	0.85
MRPRAC	RESIDENTIAL	269.1	260.7	243.0	208.1	193.1	189.3	205.1	219.7	-0.40
MRPCPC	COMMERCIAL	101.1	85.8	94.6	89.3	92.6	97.1	100.8	104.3	0.39
MRPINC	INDUSTRIAL	836.6	833.4	857.8	811.1	850.8	906.1	959.8	1007.3	0.64
MRPTRC	TRANSPORTATION	1863.7	1940.8	1979.8	2075.0	2186.1	2300.3	2448.1	2593.3	1.09
MRPFFC	FOSSIL FUEL PRODUCERS	47.8	57.1	68.4	69.5	65.6	62.1	56.3	47.8	-1.42
MRPCLC	ELECTRICITY GENERATION	159.6	81.4	83.6	59.2	86.5	113.2	133.2	78.8	-0.24
	NATURAL GAS + LPGs:									
HNLPDC	PRIMARY DEMAND	2927.2	3417.1	3543.3	3919.6	4096.2	4197.8	4384.2	4621.4	1.07
HNGPDC	PRIMARY NATURAL GAS ONLY	2694.9	3108.4	3270.6	3558.1	3718.9	3792.0	3973.9	4206.6	1.01
HLPPDC	PRIMARY LPGs ONLY	232.3	308.7	272.7	361.5	377.3	405.7	410.3	414.8	1.69
MNLEUC	END-USE DEMAND	2120.6	2372.8	2416.2	2686.8	2784.3	2831.7	2916.8	3011.7	0.89
MNLRAC	RESIDENTIAL	571.2	670.4	668.5	680.4	661.2	608.3	588.7	577.7	-0.58
MNLCPC	COMMERCIAL	409.1	471.3	488.7	514.0	530.9	548.4	570.5	596.3	0.80
MNLINC	INDUSTRIAL	1111.8	1192.0	1218.1	1449.4	1546.5	1627.0	1706.9	1784.3	1.54
MNLTRC	TRANSPORTATION	28.6	39.1	40.9	43.1	45.7	48.0	50.7	53.4	1.07
MNLFFC	FOSSIL FUEL PRODUCERS	720.5	884.6	978.5	1032.1	1065.4	1072.7	1099.9	1141.3	0.62
MNGCLC	ELECTRICITY GENERATION	86.1	160.2	148.7	200.7	246.5	293.3	367.5	468.4	4.70
	NATURAL GAS:									
HNGPDC	PRIMARY DEMAND	2694.9	3108.4	3270.6	3558.1	3718.9	3792.0	3973.9	4206.6	1.01
MNGEUC	END-USE DEMAND	1890.7	2067.6	2146.1	2329.5	2411.5	2430.6	2511.1	2601.6	0.77
HNGRAC	RESIDENTIAL	551.6	655.7	653.1	667.5	642.9	583.2	566.7	559.5	-0.62
HNGCPC	COMMERCIAL	387.8	421.3	433.0	459.6	472.8	486.3	504.9	527.5	0.79
MNGINC	INDUSTRIAL	948.7	985.3	1052.2	1194.0	1287.0	1351.9	1430.0	1504.8	1.44
HNGTRC	TRANSPORTATION	2.6	5.3	7.8	8.4	8.8	9.2	9.6	9.9	0.96
MNGFFC	FOSSIL FUEL PRODUCERS	718.1	881.1	975.8	1028.0	1061.0	1068.1	1095.2	1136.6	0.61
MNGCLC	ELECTRICITY GENERATION	86.1	160.2	148.7	200.7	246.5	293.3	367.5	468.4	4.70
	LIQUIFIED PETROLEUM GASES:									
HLPPDC	PRIMARY DEMAND	232.3	308.7	272.7	361.5	377.3	405.7	410.3	414.8	1.69
MLPEUC	END-USE DEMAND	229.9	305.3	270.0	357.4	372.8	401.1	405.6	410.1	1.69
HLPRAC	RESIDENTIAL	19.6	14.7	15.4	12.9	18.3	25.1	22.0	18.2	0.67
HLPCPC	COMMERCIAL	21.3	50.0	55.7	54.4	58.1	62.1	65.7	68.8	0.85
MLPINC	INDUSTRIAL	163.0	206.7	165.8	255.4	259.5	275.1	276.9	279.5	2.11
HLPTRC	TRANSPORTATION	25.9	33.9	33.1	34.7	36.9	38.8	41.2	43.5	1.10
MLPFFC	FOSSIL FUEL PRODUCERS	2.4	3.5	2.7	4.1	4.4	4.6	4.7	4.8	2.33

Carbon Dioxide (CO_2) Emissions (Megatonnes)

Canada

		1990	1994	1995	2000 (Projection)	2005 (Projection)	2010 (Projection)	2015 (Projection)	2020 (Projection)	Percent Change 2020/1990
	END USE SECTOR									
ETSRCC	RESIDENTIAL	43.2	45.8	46.1	42.6	40.4	37.4	37.2	37.3	-13.66
ETSCCC	COMMERCIAL	26.0	28.0	28.6	30.6	31.7	32.9	34.3	35.9	38.08
ETSICC	INDUSTRIAL	89.3	91.7	97.0	105.1	111.1	116.2	122.3	128.3	43.67
ETSTCC	TRANSPORTATION	140.1	146.7	149.5	155.0	163.1	171.8	182.8	193.6	38.19
ETSSCC	ELECTRICITY GENERATION	94.4	94.4	102.0	86.9	95.6	108.6	130.3	144.7	53.28
	FOSSIL FUEL PRODUCTION	54.7	63.2	65.5	66.7	67.4	67.6	69.7	72.0	31.63
ETSDCC	TOTAL ENERGY RELATED EMISSIONS	447.6	469.9	488.8	486.8	509.4	534.7	576.4	611.6	36.64
	BY FUEL TYPE:									
EOPFCC	REFINED PETROLEUM PRODUCTS	205.4	204.7	205.9	201.5	210.3	221.9	237.6	247.2	20.35
ELPFCC	LIQUID PETROLEUM GASES	7.2	10.0	9.9	12.0	12.9	13.9	14.2	14.5	101.39
ENGFCC	NATURAL GAS	131.9	148.7	160.3	171.0	177.8	180.8	188.8	199.3	51.10
ECKFCC	COAL, COKE & COKE OVEN GAS	95.4	96.4	102.9	91.2	96.6	105.7	123.1	137.3	43.92
ENCFCC	CO_2 STRIPPED FROM GAS PRODUCTION	7.6	10.2	9.8	11.0	11.6	12.1	12.6	13.2	73.68
ETSDCC	TOTAL ENERGY RELATED EMISSIONS	447.6	469.9	488.8	486.8	509.4	534.7	576.4	611.6	36.64

Note: Totals may not add due to rounding.

Methane (CH_4) Emissions (Kilotonnes)

		1990	1994	1995	Projection 2000	2005	2010	2015	2020	Percent Change 2020/1990
	END USE SECTOR									
ETSRMC	RESIDENTIAL	20.0	19.6	21.5	22.3	22.4	22.4	22.3	22.2	11.00
ETSCMC	COMMERCIAL	0.5	0.6	0.5	0.6	0.6	0.6	0.7	0.7	40.00
ETSIMC	INDUSTRIAL	2.6	2.8	3.0	3.2	3.4	3.6	3.9	4.2	61.54
ETSTMC	TRANSPORTATION	21.7	20.4	19.8	19.9	20.5	21.6	23.0	24.3	11.98
ETSSMC	ELECTRICITY GENERATION	0.6	0.5	0.5	0.5	0.5	0.6	0.7	0.7	16.67
	FOSSIL FUEL PRODUCTION	1360.5	1641.4	1713.4	1515.4	1378.9	1347.0	1338.3	1324.2	-2.67
ETSDMC	TOTAL ENERGY RELATED EMISSIONS	1406.0	1685.2	1758.7	1562.5	1426.4	1395.8	1388.9	1376.5	-2.10
	BY FUEL TYPE:									
EOPFMC	REFINED PETROLEUM PRODUCTS	550.9	623.3	653.9	545.8	477.9	441.1	432.6	405.7	-26.36
ELPFMC	LIQUID PETROLEUM GASES	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	100.00
ENGFMC	NATURAL GAS	743.9	957.8	1000.7	909.3	838.8	840.6	831.9	836.4	12.43
ECKFMC	COAL, COKE & COKE OVEN GAS	91.6	84.6	82.6	84.5	86.5	90.6	100.7	110.8	20.96
EBIFMC	CO_2 STRIPPED FROM GAS PRODUCTION	19.1	18.9	21.0	22.1	22.5	22.7	23.0	22.7	18.85
ETSDMC	TOTAL ENERGY RELATED EMISSIONS	1406.0	1685.2	1758.7	1562.5	1426.4	1395.8	1388.9	1376.5	-2.10

Note: Totals may not add due to rounding.

Nitrous Oxide (N_2O) Emissions (Kilotonnes)

		1990	1994	1995	2000 (Projection)	2005 (Projection)	2010 (Projection)	2015 (Projection)	2020 (Projection)	Percent Change 2020/1990
	END USE SECTOR									
ETSRNC	RESIDENTIAL	1.6	1.6	1.8	1.8	1.8	1.8	1.8	1.8	12.50
ETSCNC	COMMERCIAL	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	50.00
ETSINC	INDUSTRIAL	2.3	2.6	2.7	2.9	3.2	3.4	3.6	3.8	65.22
ETSTNC	TRANSPORTATION	28.3	41.5	43.6	46.0	48.4	50.8	54.0	57.2	102.12
ETSSNC	**ELECTRICITY GENERATION**	2.3	2.5	3.5	3.8	4.2	4.6	5.2	5.9	156.52
	FOSSIL FUEL PRODUCTION	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	50.00
ETSDNC	**TOTAL ENERGY RELATED EMISSIONS**	35.1	48.9	52.4	55.3	58.4	61.5	65.5	69.6	98.29
	BY FUEL TYPE:									
EOPFNC	REFINED PETROLEUM PRODUCTS	29.3	42.4	44.5	46.8	49.4	51.9	55.2	58.5	99.66
ELPFNC	LIQUID PETROLEUM GASES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
ENGFNC	NATURAL GAS	1.3	1.5	1.6	1.7	1.8	1.8	1.9	2.0	53.85
ECKFNC	COAL, COKE & COKE OVEN GAS	2.7	2.8	2.6	2.6	2.7	2.9	3.3	3.6	33.33
EBIFNC	CO_2 STRIPPED FROM GAS PRODUCTION	2.4	2.6	3.2	3.4	3.6	3.8	4.0	4.2	75.00
ETSDNC	**TOTAL ENERGY RELATED EMISSIONS**	35.1	48.9	52.4	55.3	58.4	61.5	65.5	69.6	98.29

Note: Totals may not add due to rounding.

Annex C

Greenhouse Gas Emissions (Megatonnes CO_2 - Equivalent)

		1990	1994	1995	Projection 2000	2005	2010	2015	2020	Percent Change 2020/1990
	END USE SECTOR									
ETSRGC	RESIDENTIAL	44.1	46.7	47.1	43.6	41.5	38.4	38.2	38.3	-13.15
ETSCGC	COMMERCIAL	26.2	28.1	28.7	30.6	31.7	33.0	34.4	36.0	37.40
ETSIGC	INDUSTRIAL	90.1	92.5	98.0	106.0	112.2	117.3	123.5	129.6	43.84
ETSTGC	TRANSPORTATION	149.2	160.1	163.5	169.7	178.5	188.0	200.0	211.7	41.89
ETSSGC	ELECTRICITY GENERATION	95.1	95.2	103.1	88.1	96.9	110.1	131.9	146.6	54.15
	FOSSIL FUEL PRODUCTION	83.4	97.8	101.6	98.6	96.6	96.2	97.9	99.9	19.78
ETSDGC	TOTAL ENERGY RELATED EMISSIONS	488.0	520.4	541.9	536.7	557.5	583.0	625.9	662.0	35.66
	BY FUEL TYPE:									
EOPFGC	REFINED PETROLEUM PRODUCTS	226.0	230.9	233.4	227.5	235.7	247.3	263.8	273.8	21.15
ELPFGC	LIQUID PETROLEUM GASES	7.3	10.0	9.9	12.0	12.9	13.9	14.2	14.5	98.63
ENGFGC	NATURAL GAS	147.9	169.2	181.8	190.6	196.0	199.0	206.8	217.5	47.06
ECKFGC	COAL, COKE & COKE OVEN GAS	98.1	99.0	105.5	93.7	99.2	108.5	126.3	140.7	43.43
ERGICC	CO_2 STRIPPED FROM GAS PRODUCTION	7.6	10.2	9.8	11.0	11.6	12.1	12.6	13.2	73.68
EBIFGC	TOTAL BIOMASS	1.1	1.2	1.4	1.5	1.6	1.7	1.7	1.8	63.64
ETSDGC	TOTAL ENERGY RELATED EMISSIONS	488.0	520.4	541.9	536.7	557.5	583.0	625.9	662.0	35.66
	TOTAL NON-ENERGY RELATED EMISSIONS [1]	75.9	76.8	76.6	73.2	79.0	85.7	95.3	105.6	39.13
	TOTAL EMISSIONS	563.9	597.2	618.5	609.9	636.5	668.7	721.2	767.6	36.12

Note: Totals may not add due to rounding.
1 Source: Environment Canada.

Annex D

Conversion Tables

Metric Units to Imperial Units — Table 1

Metric Units		Imperial Equivalent Units
1 cubic metre of oil at: (15°C and 922 kg/m^3) (15°C and 855 kg/m)	 = =	 6.29226 barrels (60°C) 6.29258 barrels (60°C)
1 cubic metre of natural gas	=	35.30101 cubic feet
1 tonne	=	1.102311 short tons
1 kilojoule	=	0.9482133 Btu
1 gigajoule (GJ)	=	approximately 0.95 million Btu
1 petajoule (PJ)	=	approximately 0.95 billion cubic feet of natural gas
1 litre (L)	=	approximately 0.22 Imperial gallon
1 kilogram (kg)	=	approximately 2.2 pounds
1 metre (m)	=	approximately 3.28 feet

Abbreviations of Terms

Table 2

Abbreviation	Prefix	Multiple
k	kilo-	10^3
M	mega-	10^6
G	giga-	10^9
T	tera-	10^{12}
P	peta-	10^{15}
E	exa-	10^{18}

Abbreviation	Definition	Abbreviation	Definition
GJ	gigagoule = 10^9 Joules(J)	m^3	cubic metre
TJ	terajoule = 10^{12}J	L	litre
PJ	petajoule = 10^{15}J	kg/m^3	kilograms per cubic metre
EJ	exajoule = 10^{18}J	t	tonne
kW	kilowatt = 10^3 Watts	Mt	megatonne
kW.h	kilowatt hour - 10^3W.h	Btu	British thermal unit
MW	megawatt = 10^3kW	Mcf	thousand cubic feet
MW.h	megawatt hour = 10^3kW.h	Bcf	billion cubic feet
GW	gigawatt = 10^6kW	Tcf	trillion cubic feet
GW.h	gigawatt hour = 10^6kW.h	bbl	barrel
TW	terawatt = 10^9kW	mmb/d	million barrels per day
TW.h	terawatt hour = 10^9kW.h	mb/d	thousand barrels per day
		C$ or $	Canadian dollars
		US$	United States dollars

Gross Energy Content Factors

Table 3

Fuel Source	Energy Content		
Natural Gas	37.23 MJ/m^3 (1)		
Ethane (liquid)	18.36 GJ/m^3		
Propane (liquid)	25-53 GJ/m^3		
Butanes (liquid)	28.62 GJ/M^3		
Crude Oil			
- Light	1m³	=	38.51 GJ
- Heavy	1m³	=	40.90 GJ
- Pentanes Plus	1m³	=	35.17 GJ
Coal			
- Anthracite	1 tonne	=	27.70 GJ
- Bituminous	1 tonne	=	27.70 GJ
- Subbituminous	1 tonne	=	18.80 GJ
- Lignite	1 tonne	=	14.40 GJ
- Average domestic use	1 tonne	=	22.20 GJ
Petroleum Products			
- Aviation Gasoline	1m³	=	33.62 GJ
- Motor Gasoline	1m³	=	34.66 GJ
- Petrochemical Feedstocks	1m³	=	35.17 GJ
- Naphtha Specialties	1m³	=	35.17 GJ
- Aviation Turbo Fuel	1m³	=	35.93 GJ
- Kerosene	1m³	=	37.68 GJ
- Diesel	1m³	=	38.68 GJ
- Light Fuel Oil	1m³	=	38.68 GJ
- Lubes and Greases	1m³	=	39.16 GJ
- Heavy Fuel Oil	1m³	=	41.73 GJ
- Still Gas	1m³	=	41.73 GJ
- Asphalt	1m³	=	44.46 GJ
- Petroleum Coke	1m³	=	42.38 GJ
- Other Products	1m³	=	39.82 GJ
Electricity			
- Hydro	1kW.h	=	3.6 MJ
- Nuclear (2)	1kW.h	=	11.6 MJ

(1) Assumes 15°C, 101.325kPa and free of water vapour. The energy content of 37.23 MJ/m^3 approximately the equivalent of 1 000 Btu per cubic foot in the imperial system. The actual energy content will vary depending on the amount of natural gas liquids (mostly ethane) contained in the gas.

(2) Typical value. Actual values at nuclear generating plants depend on specific plant efficiencies.

Emission Conversion Factors

Table 4

	CO_2		CH_4		N_2O	
COMBUSTION SOURCES						
Gaseous Fuels	(t/ML)[b]	(t/TJ)	(kg/ML)	(kg/TJ)	(kg/ML)	(kg/TJ)
Natural Gas	1.88	49.68	(4.8 to 48)	(0.13 to 1.27)	0.02	0.62
Still Gas	2.07	49.68	-	-	0.02	0.62
Coke Oven Gas	1.60	86.00	-	-	-	-
Liquid Fuels	(t/kL)	(t/TJ)	(kg/kL)	(kg/TJ)	(kg/KL)	(kg/TJ)
Motor Gasoline	2.36	67.98	(0.24 to 4.20)	(6.92 to 121.11)	(0.23 to 1.65)	(6.6 to 47.60)
Kerosene	2.55	67.65	0.21	5.53	0.23	6.10
Aviation Gas	2.33	69.37	2.19	60.00	0.23	6.86
LPGs	(1.11 to 1.76)	(59.84 to 61.38)	0.03	1.18	0.23	(9.00 to 12.50)
Diesel Oil	2.73	70.69	(0.06 to 0.25)	(1.32 to 5.7)	(0.13 to 0.40)	(3.36 to 10.34)
Light Oil	2.83	73.11	(0.01 to 0.21)	(0.16 to 5.53)	(0.13 to 0.40)	(3.36 to 10.34)
Heavy Oil	3.09	74.00	(0.03 to 0.12)	(0.72 to 2.88)	(0.13 to 0.40)	(3.11 to 9.59)
Aviation Jet Fuel	2.55	70.84	0.08	2.00	0.23	6.40
Petroleum Coke	4.24	100.10	0.02	0.38	-	-
Solid Fuels	(t/t)	(t/TJ)	(g/kg)	(kg/TJ)	(g/kg)	(kg/TJ)
Anthracite	2.39	86.20	0.02	varies	(0.1 to 2.11)	varies
U.S. Bituminous	(2.46 to 2.50)	(81.6 to 85.9)	0.02	varies	(0.1 to 2.11)	varies
Cdn. Bituminous	(1.70 to 2.52)	(94.3 to 83.0)	0.02	varies	(0.1 to 2.11)	varies
Sub-Bituminous	1.74	94.30	0.02	varies	(0.1 to 2.11)	varies
Lignite	(1.34 to 1.52)	(93.8 to 95.0)	0.02	varies	(0.1 to 2.11)	varies
Coke	2.48	86.00	-	-	-	-
Fuel Wood	1.47	81.47	(0.15 to 0.5)	(0.01 to 0.03)	0.16	8.89
Slash Burning	1.47	81.47	5.00	0.01		
Incineration						
Municipal Solid Waste	0.91	85.85	0.23	0.02		
Wood Waste	1.50	83.33	0.15	0.01		

[a] Note: Where ranges are given for emission factors, please consult the report cited below for details.
[b] The SI abbreviations M for mega (x 10^6); G for giga (x 10^9); and T for tera (x 10^{12}).

Source: A. P. Jaques, Canada's Greenhouse Gas Emissions: Estimates for 1990, Environment Canada, December 1992.

Emission Conversion Factors

Table 5

	CO_2		CH_4		N_2O	
PROCESS SOURCES	(t/t)	(t/TJ)	(g/kg)	(t/TJ)	(g/kg)	(kg/TJ)
Cement Production	0.50	-	-	-	-	-
Lime Production	0.79	-	-	-	-	-
Ammonia Production	1.58	-	-	-	-	-
Spent Pulping Liquor	1.43	107.38	-	-	-	-
Adipic Acid production	-	-	-	-	0.03	-
Nitric Oxide Production	-	-	-	-	(2.0 to 20)	-
Natural Gas Production	0.07	-	2.67	-	-	-
Coal Mining			(1.20 to 16.45)	-	-	-
Non-Energy Uses	(t/KL)	(t/TJ)	-	-	-	-
Petrochemical Feedstocks	0.50	14.22	-	-	-	-
Naphthas	0.50	14.22	-	-	-	-
Lubricants	1.41	36.01	-	-	-	-
Other Products	1.45	28.88	-	-	-	-
Coke	2.48	86.00	-	-	-	-
	(t/ML)					
Natural Gas	1.26	33.35	-	-	-	-
Coke Oven Gas	1.6	86.00	-	-	-	-
Agriculture	(kg/head/year)		(kg/head/year)		(g/kg)	(kg/TJ)
Livestock	(36 to 3 960)	-	(0.01 to 120)	-	-	-
Fertilizer Use	-	-	-	-	(1 to 50)	-
Miscellaneous	(kg/t)		(kg/t)		(g/kg)	(kg/TJ)
Landfills	182.00		66.00		-	-

Source: A. P. Jaques, Canada's Greenhouse Gas Emissions: Estimates for 1990, Environment Canada, December 1992.